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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In The Matter Of the Application Of HAWAIIAN ELECTRIC COMPANY, INC. For Approval and/or Modification of Demand-Side and Load Management Programs and Recovery of Program Costs and DSM Utility Incentives.	DOCKET NO. 05-0069

REPLY BRIEF

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REPLY BRIEF

This Reply Brief is respectfully submitted on behalf of Hawaiian Electric Company, Inc. ("HECO", or "Company"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Limited ("MECO")[1] in response to the Opening Briefs (or "OB") submitted by the other parties and participants in this Docket.

The Opening Brief of HECO, HELCO and MECO filed October 25, 2006 generally addresses the contentions included in the opening briefs of the other parties and participants. Therefore, this Reply Brief will not be all-inclusive, and will focus on those contentions that warrant further response.[2]

[1] With respect to the statewide issues (i.e., issue numbers 1-5), references to HECO or Company generally also will be applicable to HELCO and MECO. For specific DSM program-related issues (i.e., issue numbers 6-9), references to HECO or Company generally will be applicable to HECO only.

[2] References to Opening Brief of HECO, HELCO, and MECO ("HECO OB") are intended to incorporate the references to the record and authorities cited in the Opening Brief. The citations generally will not be repeated in this Reply Brief for the sake of brevity.

I. DSM PROGRAM GOALS

The first Statewide Energy Policy Issue is: Whether energy efficiency goals should be established and if so, what the goals should be for the State?

A. INTRODUCTION

HECO supports goals for energy efficiency and has developed an estimate for the amount of energy efficiency that the Company intends to achieve on Oahu over a five-year action plan implementation period[3], provided HECO receives approval to implement its proposed DSM programs, in order to meet its obligation to serve the community with reliable, cost-effective, electrical service.[4] HECO's Hearing Exhibit A provided HECO's proposed DSM program goals (in terms of MW and MWh reductions).[5] (HELCO and MECO are in the process of developing their IRP plans and will develop DSM program and proposed energy efficiency goals as part of that process.) HECO OB at 11. HECO also provided the estimated energy and demand reduction benefits (for the 2006 to 2010 period) for its seven energy efficiency and two load management programs in this docket. HECO OB at 41-42 (citing CA/HECO-IR-9 revised Exhibit 10, filed August 24, 2006).

For the HECO Companies, the DSM program goals should be based on a percentage of

[3] HECO IRP-3 Report, filed October 28, 2005, Docket No. 03-0253, also provides a 20-year assessment of DSM goals and impacts for the period 2005-2025.

[4] HECO's understanding is that the issue of statewide goals in this proceeding applies to energy efficiency only, as differentiated from load management (including demand response programs). If the Commission decides that load management programs should be subject to goals, HECO would propose that they be developed in the IRP process in the same manner as was identified in HECO's FSOP (beginning on 10, for energy efficiency program goals). HECO OB at 11-12.

[5] Reasonable demand and energy savings goals for the performance of utility energy efficiency DSM programs are important because they can serve as a "yardstick" against which actual savings can be measured, and as an expression of the parties' commitment toward improved energy efficiency. Reasonable goals, however, must (1) pertain to the intended objectives (e.g., energy savings and peak demand reductions that are consistent with the utilities' IRP Plans and with the State's Renewable Portfolio Standards, providing opportunity for all classes of customers to participate in the programs, are cost-effective, and accomplish market transformation), (2) be achievable, and (3) be measurable. HECO OB at 13-15.

the maximum achievable potential ("MAP"), as the goals will refer back to a market potential study and to the efforts of the integrated resource planning group.[6] Programs are then designed to achieve the goals. Estimated impacts for the individual energy and efficiency and load management programs are determined. If the programs are approved, then the cumulative impacts for the portfolio of energy efficiency programs, and for the load management programs, can serve as the articulated energy (kWh) and demand (kW) goals.[7] HECO further suggested that these goals can be set by sector (i.e., for the C&I and the Residential sectors).[8] Tr. (8/28) at 154-55, 213-15, 216-18 (Hee).

HECO's energy savings goal is to achieve 80% of the energy MAP by 2010, which should be expressed in megawatthours. HECO OB at 12.[9]

HECO's demand reduction goal is to achieve 50% of the demand MAP by 2010. See HECO Hearing Exhibit B, submitted August 29, 2006. The demand reduction goal takes into account contributions from the load management programs, and the load management MAP is more aspirational. See Tr. (8/29) at 255-60 (Hee). At the panel hearing, there was a discussion as to why DSM programs have not been able to achieve 100% of MAP. At the conclusion of the discussion, Mr. Hempling suggested that HECO submit a "short write-up" on the subject. See Tr. (8/29) at 258-65. HECO's discussion of this subject is attached as an exhibit to this Reply Brief.

[6] Even in California where the goals were negotiated, the negotiated goals took into consideration the results of detailed MAP analyses. See Tr. (8/28) 160 (Wikler).

[7] Stated another way, the goals need to be consistent with the approved DSM programs, and vice versa. See Tr. (8/28) at 108-09 (Abbanat).

[8] Energy efficiency goals could be stated in terms of a goal for the commercial and industrial ("C&I") sector and the residential sector. However, the goals should not be stated at the program level. If customers participate more readily in some programs than others, the goals should allow the utilities to take advantage of that response by moving its resources to those programs to acquire the savings. HECO OB at 13.

[9] The MAP includes freeriders. However, the utilities' energy efficiency goal should be 80% of MAP reduced by freeriders, since it is net savings that provide the load reduction from the demand forecast that assists the utilities with serving projected customer demand. Also, the program impacts are net of free riders. HECO OB at 12; Tr. (8/28) at 226 (Hee).

In addition, energy efficiency goals should be expressed as the aggregation of all energy efficiency programs being implemented within each utility's service territory. Further, the goals should be set at the utility level (and not at the program level). Setting the goals at the utility level in megawatt-hours and megawatts rather than at the DSM program level provides flexibility in customer choice and in the utilities' response to those choices. HECO OB at 12-13.

With respect to the development of goals, the goals should be developed using the most recent market potential studies available for the service territories served by each utility, provided that the utilities were involved to a significant degree in the development of those studies. HECO's assessment of the potential for DSM that can be accomplished on Oahu used the market potential study filed as HECO-1101 and HECO-1102 in HECO's 2005 test year rate case (Docket No. 04-0113). That assessment resulted in the expected energy and demand savings included in HECO's IRP-3 report. These estimated savings should be reasonable levels of achievement given the assumptions for the budgets, programs, and approval schedules made when developing the IRP Action plan. (The assessment of DSM resources for MECO and HELCO are currently underway in their respective IRP-3 planning processes.) HECO OB at 15-16.

Since the IRP process is intended to be an open and comprehensive process, IRP can be the source for the megawatt-hour and megawatt levels of the energy efficiency goals. HECO OB at 16 (which includes a discussion of the advantages of using the IRP process to develop the energy efficiency goals).

B. <u>POSITIONS OF THE OTHER PARTIES/PARTICIPANTS</u>

The Consumer Advocate's position is that energy efficiency goals should be established for each electric utility on an island-by-island basis, and not be set on a Statewide basis (as is the case with the Renewable Portfolio Standards goals set forth in HRS § 269-92). The Consumer Advocate also contends that the process set forth in the Commission's IRP Framework should be used to establish the island-specific goals for each utility. CA OB at 9.

In addition, the Consumer Advocate recommends that any goals established by the Commission encompass both energy efficiency measures and load management measures. The goals would include long-term targets, and short-term incremental targets. The Consumer Advocate maintained that "[t]he long-terms targets identify what an organization wishes to accomplish at some point well into the future. Goals also represent incremental targets indicating how the organization will achieve the long-term target." CA OB at 12-13.

The Consumer Advocate did not state what the energy efficiency goals should be for each of the Hawaiian islands, "because the DSM goals need to be established in the IRP process and tied to each utility's specific needs and planning objectives." CA OB at 17.

RMI's position is that goals for attainment of energy (kWh) and capacity (kW) savings should be established for each of Hawaii's energy utilities. RMI OB at 4, 6, 18-19, citing RMI FSOP at 5-11. According to RMI, generally, DSM goals for each utility service territory should be set based on findings in the utility's IRP process. The goals should be set collectively for the utility service territory and individually for the utility and third party DSM administrators. The utility and/or fund administrator should be excused or these goals should be revised if it is determined in the utility IRP process or by other studies commissioned by the Commission that the goals cannot be met cost effectively. RMI OB at 19.

RMI maintains that the Commission should set HECO's initial energy efficiency goals at 0.6% of "gross electricity sales" per year, which would be reviewed and amended based on findings in each utility IRP proceeding.[10] RMI OB at 4, 6, 18-19[11], citing RMI FSOP at 5-11; see also HSEA OB at 5, 15[12], HREA OB at 6-7[13].

Energy efficiency goals should not be based on a percentage of sales. HECO's DSM programs were designed to achieve five objectives:

(1) Achieving capacity deferral,

(2) Complying with state energy policy objectives,

(3) Ensuring cost-effectiveness,

(4) Acknowledging the need for customer equity, and

(5) Accomplishing market transformation.

To achieve these objectives HECO proposed an energy efficiency goal based on achieving 80% of the energy MAP, in megawatthours ("mwh"), by 2010. HECO prefers goals based on a percentage of MAP because the goal has a definitive link to market potential. However, a goal expressed as a percentage of actual sales does not preserve that linkage. Furthermore, actual mwh sales for the year are not known when DSM program planning and budgeting efforts for the year are conducted. Thus, the mwh energy efficiency target continues to change throughout the year, making program implementation difficult. For example, budgeting to achieve 0.6% of sales may not be adequate if sales grow more than expected. On the other hand, an explicit mwh goal is unaffected by changes in sales levels. If desired, the

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[10] RMI claimed that "HECO, in its recent IRP filing, is proposing an effective reduction of 0.6 percent of gross sales." (RMI FSOP, p. 10)." See RMI OB at 19 n.9. HECO noted that HECO's proposal was closer to 0.5%. Tr. (8/28) at 115 (Hee).

[11] RMI contends that, in a future rulemaking, it should be determined that the RPS goal of 20% be met entirely with renewables as authorized by Act 162 (SLH 2006).. RMI OB at 19. As acknowledged by RMI, such a contention is beyond the scope of this proceeding and should be addressed in another proceeding.

[12] Based upon hearing testimony and the experience in other states, HSEA recommends "a benchmark annual reduction of total load on the order of 0.6% to 1.0% . . . ." HSEA OB at 5, 15.

[13] HREA maintained that a "Demand-Side Management Portfolio Standard" be implemented of "1% per year of overall electric demand (utility sales)". Under HREA's proposal to have the definitions of DSM and DSM programs revised, DSM programs would include both the "utility-side and customer-sides of the meter". HREA OB at 4, 6-7.

mwh goal can be converted to a percentage of sales measure, using an assumed year-end sales level. See HECO FSOP at 10-14; Tr. (8/28-29) at 73-74, 118-120, 258-267 (Hee, Waller, Wikler, Blume); HECO OB at 12-17.

RMI provided the basis for its proposed 0.6% of sales target in its response to HECO/RMI-FSOP-IR-102. However, the amounts of DSM achieved assumed by RMI in its calculation has since been updated in the August 24, 2006 revisions to HECO's response to CA/HECO-IR-9. The projected levels of energy efficiency DSM impacts are now somewhat lower that those assumed by RMI to reflect program level, participation, and unit level impact assumptions, as shown in Exhibit 8 of that revised response. Furthermore, RMI held sales constant between 2005 and 2009 at 7,480 gwh, which is lower than the 2005 test year sales estimate in Docket No. 04-0113, of 7,856 gwh. See HECO-R-201 in Docket No. 03-0113. The combination of an overestimate of DSM sales impacts and underestimate of sales results in an unrealistic DSM sales reduction achievement as a percentage of sales.

HREA's proposal to set the energy efficiency target at 1% sales is arbitrary and ignores local market conditions and the market potential for energy efficiency measures that are contained in the MAP. Therefore, HREA's proposal should be rejected.

HSEA maintains that the utility should be required to exceed 80% of MAP under certain high electricity and fuel price scenarios. HSEA OB at 5. Greg Wikler, HECO's consultant, testified that using 80% of MAP as a basis for goals is reasonable. First, the MAP studies will be updated on a regular basis as part of the IRP process. In addition, the MAP studies will take into consideration the economic and technical analyses necessary to assess the viability of energy efficiency programs. HECO OB at 12.

HSEA recommended that the Commission require HECO to accelerate the three-year

MAP cycle and also require HECO to use current oil price and electricity rates in its avoided cost and cost-effectiveness calculations. HSEA OB at 4-5. HECO stated that updating the MAP study that was completed as part of HECO's IRP-3 could be performed in two to three months. HECO OB at 12. HECO prefers to do such an update as part of its IRP-4 process.

While the electric utilities and the Consumer Advocate favored the establishment of island-specific goals, HREA favored the "one size fits all" approach. HREA OB at 7. However, HREA proposed a DSM Portfolio Standard ("DPS"), in which DSM is broadened to include conservation, load management and efficiency resources, of 1% per year of overall electric demand (utility sales) on an on-going basis. HREA OB at 3-5, 6-7.

HECO does not agree with HREA's proposal. As previously discussed, the energy efficiency goals should be based on a percentage of MAP and not based on a percentage of sales. In addition, energy efficiency goals should be developed within each utility's service territory. If goals are set on a statewide basis, the identities and differences that exist in each utilities' service territory could be lost. HECO OB at 12.

The Consumer Advocate's position on this is similar to HECO's position. The Consumer Advocate contends that establishing uniform statewide goals as recommended by HREA represents a "'one-size-fits-all' approach that makes little practical sense. Uniform, statewide goals similar to the RPS ignore the unique geographic, economic, political, social, and cultural factors affecting each service territory in Hawaii and the utility's ability to achieve such goals." CA OB at 14-15. Also, it makes little sense to establish yet another uniform, statewide goal for energy efficiency measures when such goals arguably already exist in the existing RPS statutory provisions. CA OB at 15-16.

In addition, the Consumer Advocate maintained that Hawaii's energy industry is unique in that each electric utility provides service on a given island as a stand-alone utility. The utilities are not interconnected, and there is a need to be confident that each utility can reliably meet customer demands; this requires that the DSM goals for each utility be realistic. It is important to establish goals that can reasonably be achieved by each utility in order to ensure that the utility has sufficient generation to meet the energy needs of its customers. If the goals are too optimistic, such that they are established too high, the utility may rely on the expected energy savings associated with such goals and not have sufficient generation to serve the customers' needs should the goals not be achieved as anticipated. The potential result is that there may be insufficient generation to reliably serve all customer needs, which is not in the utility's or its customers' best interests. CA OB at 16-17.

Further, the Consumer Advocate maintained that establishing goals on an island-by-island basis takes into consideration the unique circumstances of the utility serving each of the Hawaiian islands (e.g., the type of customer base, customer load patterns, size of service territory, size and types of generation available to serve customers' needs, availability of specific types of resources, etc.) CA OB at 16.

The Consumer Advocate, however, did not state what the energy efficiency goals should be for each of the Hawaiian islands, "because the DSM goals need to be established in the IRP process and tied to each utility's specific needs and planning objectives." CA OB at 17. HECO, however, agrees with other parties that the Commission can set the initial goals in this proceeding for HECO, since the proposed programs were developed in the HECO IRP-3 process. See also Tr. (8/28) at 158-60 (Datta).

C. OTHER MATTERS

1. DSM Definition

HSEA and HREA propose that the Commission adopt the October 2001 California Standard Practice Manual definition of "demand-side management". HSEA OB at 3-4, 15; HREA OB at 3-4. HREA goes further, and proposes that the Commission establish a DSM portfolio standard, apparently by proposing legislative changes to the RPS law. HREA OB at 4-5, 7-8.[14]

The California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects ("CSPM") establishes standardized procedures in California for calculating benefit-cost tests representing a variety of perspectives -- participants, non-participants, all ratepayers, society, and the utility. According to the October 2001 revised manual, "[t]his manual employs the use of general program categories that distinguish between different types of demand-side management programs, conservation, load management, fuel substitution, load building and self-generation." CSPM at 2.

The October 2001 revised manual also stated that "[c]onservation programs reduce electricity and/or natural gas consumption during all or significant portions of the year. 'Conservation' in this context includes all 'energy efficiency improvements'. An energy efficiency improvement can be defined as reduced energy use for a comparable level of service, resulting from the installation of an energy efficiency measure or the adoption of an energy efficiency practice. . . . Load management programs may either reduce electricity peak demand or shift demand from on peak to non-peak periods." CSPM at 2.

Self-generation was added as a separate category because, in the Spring of 2001, a new state agency - the Consumer Power and Conservation Financing Authority - was created. "This

[14] This is also the position taken by the County of Maui. See COM OB at 5-6.

agency is expected to provide additional revenues in the form of state revenue bonds that could supplement the amount and type of public financial resources to finance energy efficiency and self generation activities." CSPM at 1-2. As a result, a definition of self-generation as a type of "demand-side" activity was included.[15]

Regardless of whether self-generation is viewed as a demand-side or a supply-side activity, it is beyond the scope of this proceeding. This proceeding does not encompass fuel substitution, load building or self-generation activities, and the Commission has recognized that these activities are subject to different considerations.

In Decision and Order No. 14638 ("D&O 14638"), issued April 22, 1996 in Docket Nos. 94-0010, 94-0011 & 94-0012 (Consolidated), in which the Commission approved the initial C&I energy efficiency DSM programs, the Commission found that:

> The issue of whether HECO's DSM programs should include gas fired technologies was raised by Gasco and considered by the commission in Docket No. 7257. In Decision and Order No. 13839, we said that fuel substitution DSM programs would not be administratively viable for separately owned electric and gas utilities and that HECO cannot be required to promote a competitor's product under the guise of a DSM program for HECO. We also rejected the fuel choice DSM measures that Gasco included in its own IRP docket. Gasco presents no new arguments in these dockets to support its position that HECO's DSM programs should include gas fired technologies. We, thus, affirm our findings in Decision and Order No. 13839 and Decision and Order No. 13925 and conclude that fuel substitution measures are not appropriate in these circumstances.

D&O 14638 at 8-9, citing Decision and Order No. 13925, filed May 24, 1995 in Docket No. 7261. Gasco's proposed "fuel choice" DSM programs were load building programs.

Distributed generation was the subject of a separate generic docket, Docket No. 03-0371.

[15] "AB 970 amended the Public Utilities Code and provided the motivation to develop a cost-effectiveness method that can be used on a common basis to evaluate all programs that will remove electric load from the centralized grid, including energy efficiency, load control demand-responsiveness programs and self-generation. Hence, self-generation was also added to the list of demand side management programs for cost-effectiveness evaluation."
CSPM at 3.

Some of the parties in that proceeding made the same proposal to treat customer sited distributed generation ("DG") as DSM. The Commission did not adopt that concept in the DG docket, and should not do so in this proceeding.

In addition, there is no groundwork laid to establish goals or programs for self-generation technologies. (Tr. 8/28) at 177 (Hee). The appropriate witnesses to discuss DG technologies were not present. Tr. (8/28) at 178-79 (Williams).

Those parties who propose that distributed generation resources like PV be treated like demand-side measures that are included in DSM programs apparently want utilities to pay incentives to customers to install such measures. Distributed generation, however, whether fueled by renewable energy resources or by fossil fuels, should not be confused with energy efficiency DSM measures. DSM Programs are designed to influence the use of energy. The IRP Framework defines DSM Programs as "programs designed to influence utility customer uses of energy to produce desired changes in demand. It includes conservation, load management and efficiency resource programs." See IRP Framework, Part I. DG is a resource that supplies energy. The IRP Framework definition of Supply-side programs is "programs designed to supply power. It includes renewable energy." IRP Framework, Part I. Under this definition DG is clearly a supply-side resource, and not a DSM measure.

Further, distributed renewable energy generation resources already receive substantial incentives, in the form of federal and state government tax credits (to help buy-down the cost of renewable technologies) and state laws such as net energy metering and renewable portfolio standards (to help stimulate renewable development). Renewable DG is provided its own, unique incentive mechanism, in the form of net energy metering, which is the subject of a different proceeding. See Docket No. 2006-0084, Order No. 22380, issued April 10, 2006.

Differences also exist between DSM measures and some DG resources in terms of ownership, operation and maintenance. The measures installed pursuant to energy-efficiency DSM programs generally are replacements for equipment, fixtures, or processes that are used in the customer's business or home, such as energy efficient lighting, or motors, or water heaters. Thus, DSM measures generally can be "operated" and "maintained" (to the extent that is necessary) using the O&M expertise or resources that the customer already has. These DSM measures, which allow electricity to be used efficiently, or substantially reduce the use of electricity (such as is the case with solar water heaters, where electricity is the back up water heating source), are distinctly different from DG resources, which generate electricity. The option of utility ownership of a DG resource, such as a combined heat and power system, is desirable to customers precisely because they often do not want to own, operate and maintain generating resources.

DSM programs are not currently designed so as to avoid any "burden" on non-participants. Incentives are paid to customers for "cost effective" programs, even where individual customer rates are increased when the utility recovers the program costs and lost contributions to fixed utility costs. (On a total customer basis, energy <u>bills</u> should be reduced because of the reduction in energy use.) Whereas <u>all</u> customers benefit from the demand savings (i.e., the kw savings) resulting from DSM program measures, participating customers are the primary beneficiaries of the energy savings. (At the same time, there is a benefit to the State as a whole, including non-participating customers, due to the reduction in the use of oil.)

One of the primary justifications for the current approach to DSM programs is that there is a broad array of DSM measures available under the DSM programs, and a broad opportunity for customers to participate (and to directly benefit from bill savings). That is not generally the case with DG.

2. RMI's PAYS Proposal

RMI proposes that HECO be directed to develop a "'Pay-As-You-Save' low income solar water heating and photovoltaic program." RMI OB at 24-25. HECO's position, however, is that the definition of demand-side management refers to the customer's use of energy, and that, HECO believes, is specifically energy efficiency and load management measures that are included currently in the Energy Efficiency Docket in HECO's proposed programs. Tr. (8/28) at 177 (Hee).[16] The legislature did not include photovoltaic ("PV") systems in Act 240, and HECO does not intend to include PV in its Pay-As-You-Save ("PAYS") tariff.

Solar water heating and PV systems both use solar energy. But PV systems are not candidates for inclusion in energy efficiency DSM programs. The distinction between DSM measures and DG is blurred somewhat in the case of small DG resources, such as residential PV systems, but there are still substantial differences between solar water heating and PV systems in terms of function, cost, benefits to and impacts on non-participants, and mechanisms for utility support.

Solar water heaters are passive collectors of solar energy. The collected energy is directly transmitted into hot water without the generation of electricity. In addition to being a renewable energy resource, solar water heaters are an important DSM measure because water heating is generally the largest residential electric load and reducing this load can help to shave the Companies evening peak demand. PV systems are also a renewable energy resource, but they generate electricity. The concept of net energy metering is based on the recognition that such a system may feed electricity into the grid, as well as reduce a customer's own use of

[16] By Order No. 22974, issued October 24, 2006 in Docket No. 2006-0425, the Commission instituted a Proceeding to Investigate the Issues and Requirements Raised by, and Contained in, Hawaii's Solar Water Heating Pay As You Save Program, Act 240, Session Laws of Hawaii (2006).

electricity. Tr. (8/28) at 231-36 (Hee), -186 (Wikler).

HECO supports solar water heating through the incentives in its highly successful REWH and RNC Programs, and will include solar water heating in its Pay-As-You-Save tariff. HECO supports PV systems through its State-mandated net energy metering tariff, as well as through its Sun Power for Schools Program and other demonstration projects. The State of Hawaii provides substantial taxpayer support to both solar water heaters and PV systems through a renewable energy tax credit.

II. <u>DSM PROGRAMS</u>

A. <u>APPROVAL OF ENERGY EFFICIENCY DSM PROGRAMS</u>

1. <u>Issue</u>

The sixth issue is: "Whether HECO's seven (7) Proposed Demand Side Management ("DSM") Programs (i.e., the CIEE, CINC, CICR, REWH, RNC, RLI, and ESH programs), the Residential Customer Energy Awareness ("RCEA") Program, and/or other energy efficient programs will achieve the established energy efficiency goals and whether the programs will be implemented in a cost-effective manner?"

The seventh issue is: "If utility-incurred costs for the Proposed DSM Programs are to be included in base rates, what cost level is appropriate, and what the transition mechanism for cost recovery will be until the respective utility's next general rate case?" This issue is similar to the fourth issue: "For utility-incurred costs, what cost level is appropriate?"

2. <u>Design of DSM Programs</u>

HECO's position is that the Commission should approve its seven energy efficiency DSM programs (the CIEE, CINC, CICR, REWH, RNC, RLI, and E$H programs) as modified during these proceedings. <u>See</u> HECO OB at 67-127. The Consumer Advocate has acknowledged the general reasonableness of all seven of these programs,[17] and other parties to this proceeding generally favor moving forward with the programs at this time.

For example, RMI recommends that HECO's proposed energy efficiency program portfolio be given immediate, but "conditional" approval, but "subject to ongoing review by the Commission (i) based on annual reports of program accomplishments, costs and cost recovery and (ii) based on any pertinent findings from review of HECO's pending IRP application." RMI OB at 4-5, 20-24.

Similarly, HSEA recommends that the Commission adopt the DSM programs proposed by HECO on an expedited basis, pointing out that, "There appears to be unanimous agreement among the participants that HECO's proposed DSM programs are both robust and of critical importance in light of the utility's persistent reserve margin shortfall." HSEA OB at 3, 12.

HREA likewise "observes that the benefits provided by and success of the REWH and RNC programs are well-established," but the major thrust of its participation in this proceeding seems to be directed towards the establishment of a SWAC C&I program. HREA OB at 14; see HREA OB at 14-28. HREA, which originally proposed a competitive bidding model for the provision of DSM programs, and now proposes a public benefits fund model, originally opposed the starting of new programs by HECO pending the results of this docket. HREA OB at 12. However, HREA is "now open to approval of these new programs on an interim, pilot basis." HREA OB at 15. In fact, HREA recommends that the Commission direct the utility to "[a]ggressively implement its HECO's proposed programs on an interim basis for 3 to 5 years . . . ." HREA OB at 13.

The Consumer Advocate's position is that all of the proposed DSM programs, with the

[17] See CA OB at 61-67.

exception of the RCEA program, should be approved by the Commission. CA OB at 10. HECO's has addressed its proposal to increase customer awareness of conservation and energy efficiency through a multi-faceted advertising campaign in lieu of a formal RCEA Program in its 2006 test year rate case, Docket No. 04-0113. Thus, pending the Commission's determination on this matter in the rate case, HECO has not included further RCEA Program information in this Docket. See HECO OB at 23-26, 127-32.

HECO's load management programs have already been approved. The RDLC Program was approved by Decision and Order No. 21415, issued October 14, 2004, and the CIDLC Program was approved by Decision and Order No. 21421, issued October 19, 2004. The Commission has since approved various modifications to these programs. See HECO OB at 132-33. Rather than addressing further load management program modifications in this Docket, HECO will propose such changes in separate filings later this year. See HECO OB at 133.

B. DSM PROGRAM DEVELOPMENT

1. The Consumer Advocate

The Consumer Advocate contends that there were "deficiencies" with respect to the development of the DSM programs, because "HECO was not sufficiently clear in communicating the relationship between the seven 'objectives' that HECO developed at the onset of its IRP planning process and the specific DSM programs that it proposes to implement." CA OB at 52, citing CA FSOP at 47-54.

The Consumer Advocate also identified what it termed the nine essential program design steps:

1. Identify and establish the basic resource planning objectives and, consequent energy- and capacity-savings goals that the DSM programs are to achieve.

2. Through primary and secondary research, segment the utility's customer base into

different types of customers, and identify how electricity is currently being utilized by those customers.

3. Identify new technologies and equipment that can be deployed to improve the efficiency with which electricity is utilized by the various customer segments and end uses.

4. Estimate the maximum potential reductions in total system peak load and total system energy requirements that can be achieved through the deployment of these technologies and equipment.

5. Design specific programs and delivery mechanisms to encourage target customer groups to implement the various DSM measures.

6. Assess the cost-effectiveness of each DSM program by estimating all program benefits and costs, utilizing industry standard benefit/cost tests.

7. Establish the optimum portfolio of programs to be implemented (i.e., the desired expenditures on individual programs) to best achieve the objectives and goals established in step 1 above. Ideally, the desired level of DSM expenditures on each program would be established in an integrated resource planning process where supply- and demand-side alternatives are compared directly against one another. It is possible to optimize among only DSM alternatives (e.g., assuming a certain pre-determined "set aside" for DSM), but this is less desirable because it may fail to achieve an overall least-cost plan.

8. Design procedures to: (a) monitor and evaluate the progress in implementing each program and (b) measure actual energy- and capacity-savings over the life of the measures installed.

9. Develop appropriate reporting mechanisms so that the Commission, the Consumer Advocate, and other interested parties can be kept apprised of the program results and progress.

CA OB at 49-50, citing CA FSOP at 42-44.

With respect to development of an "optimal" portfolio, the Consumer Advocate contended that it -

> has not been persuaded that an optimal DSM program portfolio has been achieved by HECO. Nonetheless, the Consumer Advocate is satisfied that HECO's proposals are adequate under the circumstances, and that further delay in implementing these programs would be contrary to ratepayer interests. The Consumer Advocate anticipates, based on communications from the Company during the course of the proceedings, that <u>HECO will in this Docket provide additional information to explain its strategies for implementing demand-side programs. Moreover, the Consumer</u>

Advocate anticipates that such explanations (i.e., drawing the link between IRP planning objectives and DSM program proposals) will become a routine part of HECO's IRP processes.

CA OB at 53-54 (underlining added).

In informal discussions, the Consumer Advocate stated that it learned that three primary considerations drove the Company's selections of DSM programs to pursue:

(1) Maximize capacity (MW) savings in order to mitigate the possible effects of the Company's reserve capacity shortfall;

(2) Make DSM programs available across a broad range of customer classes and sub-groups; and

(3) Implement DSM programs (i.e., increase program budget levels) to the point where practical experience with these programs and eligible customers dictates that maximum levels of market penetration (e.g., based on DSM program acceptance rates by customers) would be achieved.

CA OB at 52-53.

In order to address the Consumer Advocate's concerns, the following subsections summarize the process by which HECO developed its DSM programs, based on its IRP objectives. In substantial part, HECO followed the program design steps outlined by the Consumer Advocate.

2. DSM Program Objectives

The energy efficiency programs represented in the docket are the result of a process that was intricately linked to the goals and objectives that HECO set forth during the IRP-3 development process. Specifically, five goals and objectives were identified and adhered to in the program development process:

(1) Achieving capacity deferral,

(2) Complying with state energy policy objectives,

(3) Ensuring cost-effectiveness,

(4) Acknowledging the need for customer equity, and

(5) Accomplishing market transformation.

See Tr. (8/28) at 39-40, 154, 218 (Hee); Tr. (9/1) at 1074 (Williams).

As it initiated the development of the program portfolio, HECO considered how best to strike a balance between each of the five objectives. The program portfolio, in its entirety, satisfies each of these objectives:

(1) The capacity deferral from the portfolio represents 19.6 megawatts (net system level) in the first year, growing to 85.9 megawatts by the fifth year of the program;

(2) Hawaii's four energy policy objectives[18] are complemented by the programs represented in the Docket;

(3) The program portfolio has a TRC benefit/cost ratio greater than 1.00. The portfolio also achieves a positive benefit/cost ratio from the Utility Cost and Participant test perspectives;

(4) The programs reach all HECO customers with rebates and services that help those customers reduce their electricity costs and improve their operating efficiencies even though individual programs such as the REWH Program have a TRC ratio less than 1.00; and

[18] The four objectives, as defined by Hawaii Revised Statutes, Chapter 226-18, "Objectives and policies for facility systems - energy," are as follows:

1. Dependable, efficient, and economical statewide energy systems capable of supporting the needs of the people;
2. Increased energy self-sufficiency where the ratio of indigenous to imported energy use is increased;
3. Greater energy security in the face of threats to Hawaii's energy supplies and systems; and
4. Reduction, avoidance, or sequestration of greenhouse gas emissions from energy supply and use.

(5) The programs include components designed to transform the market for energy efficiency products and services such that over the long term the market will supply these products and services without the need for utility participation.

See HECO OB at 40-42; Exhibit A to November 3, 2006 filing.

3. IRP DSM Program Design and Resource Requirements

As summarized in HECO's Opening Brief, Global Energy Partners, LLC ("Global") developed two studies that formed the basis for HECO's DSM program design. The Phase I study, "Assessment of Energy Efficiency and Demand Response Potential," assessed the Maximum Achievable Potential ("MAP") for DSM in HECO's service territory. See HECO-1101.[19] The Phase II study, "Assessment of Hawaii's Energy Efficiency and Demand Response Potential," defined the programs that could potentially realize a portion of that potential and then estimated the impacts, expenditures, and cost-effectiveness for each program. See HECO-1102. Both studies were conducted on behalf of HECO to explore the potential of DSM for its IRP-3 resource plan.

Savings impacts were estimated and validated relative to HECO's past program accomplishments by utilizing an engineering simulation model known as the Building Energy Simulation Tool ("BEST"). The BEST model simulates energy loads for specific types of buildings and energy efficiency measures using Oahu-specific parameters such as building size, the age of the building, and historical weather. Once BEST runs were completed, the savings results were compared with HECO's reported savings from its recent evaluation reports submitted to the Commission. As necessary, adjustments were made in the savings calculations to more accurately reflect actual conditions. HECO T-11 at 6.

[19] HECO-1101 contains the main report from the Phase I study. A number of appendices that are referenced in the study were not included in HECO-1101 due to their large volume, but were made available upon request.

If cost (i.e., near term rate impacts) were not a consideration then the amount of average and peak electric load reductions that could be achieved for each island would theoretically approach the MAP. However, the ability to achieve the MAP is constrained by the degree to which the DSM programs are accepted by the market. Added program expenses to overcome market barriers and increase market acceptance by raising customer incentives and extending outreach programs would help, but may not result in attaining this maximum upper boundary for energy efficiency and load reduction savings. Response to LOL/HECO-IR-2. See also Exhibit "A" to this Reply Brief.

The Phase II Study referenced in HECO-1102 included four objectives, each of which is addressed in significant detail in HECO-1102:

> (1) To identify new programs that HECO could implement to increase its acquisition of DSM energy and demand reductions;
>
> (2) To develop descriptions and designs for each program identified;
>
> (3) To develop projected impacts and budgets associated with each program; and
>
> (4) To conduct a cost-benefit analysis in order to obtain an indication that the proposed programs are cost-effective.

HECO T-11 at 6-7.

The Phase II energy efficiency effort drew information from (1) HECO's five existing DSM energy efficiency programs, (2) HECO's then pending DSM program applications with the Commission for the RCEA, RDLC, and CIDLC Programs; and (3) benchmark experience from other utility energy efficiency program efforts. HECO T-11 at 7.

The programs represented in the portfolio were ultimately developed through a collaborative process that involved the input from key stakeholders in HECO's IRP-3 public participation process. These stakeholders were brought together in a forum to present their ideas and options for moving HECO into the next generation of utility-based energy efficiency programs. The forum, known as the Demand-Side Technical Committee ("DSTC"), convened on five occasions between December 2003 and April 2004 to conduct its work. See HECO T-11 at 8-9.

The following steps were used to develop the program designs and budgets that were initially proposed in HECO's 2005 test year rate case, Docket No. 04-0113[20]:

(1) Development of a market potential study and the identification of market barriers for energy efficiency and peak load reduction measures, which provides estimates of the Maximum Achievable Potential ("MAP") for both energy and demand savings[21];

(2) Selection of target markets[22];

(3) The design of programs to overcome market barriers in the target markets[23];

(4) Determination of annual energy and demand savings by applying benchmark data from:

(a) Actual performance of HECO's existing programs,

(b) Existing market infrastructure conditions, and

(c) DSM program experience of mainland utilities;

(5) Comparison of estimated savings to DSM resource goals (e.g., 80% of energy MAP by year 2010); and

(6) Development of program budgets to reflect the resources necessary to attain the DSM resource goals.[24]

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[20] These steps parallel the best practices identified by the July 2006 National Action Plan for Energy Efficiency ("NAP") that EPA facilitated along with the U.S. Department of Energy. See NAP, Chapter 6: Energy Efficiency Program Best Practices (summarized on pages 6-6 through 6-11). A copy of the NAP was attached as Exhibit A to HECO's Response to EPA Report. A copy of the NAP was attached as Exhibit A to HECO's Response to EPA Report.

[21] NAP at 6-15 to 6-17.

[22] NAP at 6-18 to 6-20.

[23] NAP at 6-30.

[24] NAP at 6-20.

See HECO OB at 34-38; Tr. (8/28) at 205, 256-57 (Wikler).

As indicated above, several important sources of information were provided:

(1) HECO's Existing Energy Efficiency Programs were examined in order to determine how best to expand on the well-documented previous successes of HECO's energy efficiency programs and initiatives;

(2) The Study of MAP Savings was a critical input for the DSTC as it defined the magnitude of MAP savings, and identified the market segments and end-uses where those future savings could be achieved; and

(3) Benchmark Experience was a key factor in the development of programs and initiatives that were considered by the DSTC. This experience came from a variety of energy efficiency programs and initiatives that have been implemented by other utilities around the US, identifying the various attributes of these programs which might be applicable and transferable to conditions specific to the island of Oahu.

These three nodes of information were then presented to the DSTC over the course of its meetings. The result of this effort was a set of energy efficiency programs, comprised of both expansions to existing programs plus newly proposed programs. See HECO-1102 at 3-4. From there, parameters were developed for each program in terms of energy and peak demand savings as well as projected expenditures which were then incorporated into HECO's IRP-3 integration models.

These parameters represented informed judgment about the available market and the financial resources needed to ensure that the customers adopt the program measures for both existing programs projected into the future and new programs not yet implemented in HECO's service area. For HECO's existing programs, historical records of program participants were a key determinant that helped to gauge the remaining market that could be attracted to the program. The projected number of participants for each of the programs was based on these studies, combined with the operational experience of the HECO program implementation staff. Historical expenditures in terms of rebate levels, marketing initiatives, and program administration were all taken into consideration in order to define appropriate expenditure levels to achieve these participation goals. See Tr. (8/28) at 205, 256-57 (Wikler).

For the proposed new programs, HECO studied the market for various end uses such as air conditioning, lighting and appliances. These studies were based on a variety of market research efforts to identify the size of the market under consideration. Then, drawing upon the benchmark experience of other utilities that have implemented similar programs, participation levels were specified. Benchmark experience was also a key factor in determining the rebate levels, the amount of marketing, and the program administration necessary to achieve these participation levels. See id. at 205.

The result was a portfolio of energy efficiency and load management DSM programs, which was included in HECO's 2005 test year rate case filing.

4. **Changes in this Docket**

In its FSOP filed June 1, 2006, HECO updated certain DSM program design issues. The changes made to HECO's DSM program assumptions, including assumptions as to participation, measure unit level impacts, and line item expenses, were identified in Exhibit 8. Exhibit 9 included additional information requested by the Consumer Advocate and the EPA in their respective responses to HECO's Interim DSM program proposals as ordered by the Commission in Interim D&O No. 22420. HECO FSOP at 43.

C. SPECIFIC DSM PROGRAM DESIGN ISSUES

1. Independent Evaluation

If the Commission continues utility-administered DSM programs, HECO proposes that a single independent third-party evaluator – who would be paid out of funds collected from the DSM surcharge as directed by the Commission – be responsible for conducting an evaluation of the utility and non-utility DSM programs and program impacts approximately every three years. See Response to DOD/HECO-IR-1-18; see also Tr. (8/31) at 975-76 (Hee).[25]

RMI contends that unless the Commission and/or Consumer Advocate are able and willing to more effectively review HECO's annual reports, a qualified independent contractor should be retained for this purpose. See RMI OB at 18. To the extent the programs are administered by a third party, the need for an independent evaluator would be obviated.

RMI argues that annual reviews are necessary because HECO's reports are not presently being reviewed by Hawaii's regulators. See RMI OB at 17. RMI's argument for annual reviews is tied to its proposal that a significant percentage of the utility incentives only be paid upon completion of the independent evaluation. As a preliminary matter, HECO objects to the proposition that the utility only receive incentives upon completion of an independent annual evaluation because of the timing lag in payment.[26] Setting that proposition aside, HECO opposes annual independent evaluation, because it could be expensive and time consuming, and would add to ratepayer costs. Data collection can be ongoing each year. However, the costs for a three-year study are lower because the sample size of participating customers can be smaller

[25] Since under this proposal, the Commission would be overseeing and paying for the evaluation, the costs incurred for the evaluation should not be included in the calculation of any shareholder incentive. See Response to DOD/HECO-IR-1-18.

[26] Once the program year ends, the data collection, analysis, and reporting can take one to two years to complete. In the meantime, the utility would not be able to recover its incentive. Instead, utility incentives should be paid concurrently with the efforts to earn them. Reconciliation of the incentives to reflect results of the evaluation can take place every three years.

when there are more installations to choose from. Thus, the costs to select, log, and collect data are lower.

Similarly, the Consumer Advocate expects that, to the extent its proposed sequence of annual filings and reviews by the Commission are initiated and conducted "fairly and routinely," it would become unnecessary in the future to "conduct in-depth reviews of every program every year." Rather, the Consumer Advocate anticipates that "a fairly thorough evaluation of a given program might occur and may not be revisited for a period of two or three years . . . ." See Tr. (8/31) at 979 (Abbanat). As stated supra, HECO agrees that a three year time-span between independent party evaluations is reasonable. See Tr. (8/31) at 979-80 (Hee).

The Consumer Advocate proposes that the Commission establish dockets to consider program evaluations and ensure regulatory oversight over energy-efficiency and DSM efforts, but acknowledges that the use of docketing might increase the Commission's workload over the short-term. CA OB at 70, citing CA FSOP, Appendix C at 2-4. HECO notes that independent evaluation would render this proposal moot. In addition, substantial questions were raised as to the efficiency of such a process during the panel hearings. LOL, for example, voiced its concern regarding the bureaucratic redundancy of opening up an additional docket for the purpose of setting up a time within a docket for the evaluation of a report such as a DSM review. See Tr. (8/31) at 990-91 (Curtis).

2. CICR Program Payback Period

The Consumer Advocate asserts that 1.5 years is an appropriate payback period for the CICR Program. See CA OB at 63. Contrary to the Consumer Advocate's assertion, HECO proposes to reduce the payback period under both the CINC and CICR programs from two years to one year. HECO OB at 88. The two-year payback did not provide enough of an incentive for customers. Under the two-year payback regime, there were some measures with payback periods between one and two years that should have been installed by customers, but for some reason were not. HECO therefore proposes the reduced payback period in recognition of the utility's need to incent customers to install those measures. See Tr. (8/29) at 291-93 (Hee).

The Consumer Advocate is in error in believing that HECO's proposed CINC program has a 1.5-year payback threshold for the non-prescriptive measures installed under that program.[27] In its Interim DSM Proposals letter to the Commission dated December 12, 2005, HECO proposed to eliminate the two-year payback threshold for both the CINC and CICR Programs. See HECO's Interim DSM Proposal letter, Exhibit "A", at 10, 13, Source/Notes #3. HECO now proposes to establish the threshold at one year. See HECO OB at 88. The Consumer Advocate's belief that the payback period for the CINC program is 1.5 years, is predicated on a misinterpretation of the information provided by HECO in HECO's Tailored Energy Efficiency Plan. See HECO-1102. The cite referred to by the Consumer Advocate is an example of custom programs that other organizations have implemented. In this case, the cite refers to the Design 2000 Plus Program, implemented by National Grid.

The one-year payback threshold is reasonable, and should be approved in this Docket.

3. CICR Program Incentives

It is HECO's position that demand incentives under the CICR Program should be paid out to customers for any measures leading to demand reduction, and not only for measures that reduce demand during HECO's priority peak, 5:00 p.m. to 9:00 p.m. HECO's proposed change reflects the added value of capacity reductions during afternoon peaks and allows the customer and HECO to pre-determine most demand incentive payments. See HECO OB at 89-90.

[27] See CA FSOP at 67.

Conversely, the Consumer Advocate argues that the additional payments are inappropriate at this time. See CA OB at 64. The Consumer Advocate's position is incorrect.

From a capacity deferral standpoint, the load reductions at the system peak achieved through C&I energy efficiency DSM programs may be less than the load reductions achieved coincident with the customer's load profile. However, shortfalls in reserve capacity can occur anytime during the day depending on system load and unit outages. Thus, reliability is of concern at any time of the day. C&I energy efficiency DSM programs enhance system reliability by providing load reductions during the day and also at times of the system peak. Enhancing reliability is encompassed in the first of the state's energy objectives: "Dependable, efficient, and economical statewide energy systems capable of supporting the needs of the people."[28] Therefore, HECO supports the payment of rebates on the basis of customer peak demand reductions. See HECO OB at 89-90; HECO FSOP at 48-49.

Payment of rebates on this basis also makes participation by customers in C&I DSM programs more attractive. In most cases, the reduction in the customer's demand is relatively simple to determine via engineering calculations and can be determined with relative accuracy before the DSM measure(s) are installed. Thus, when the rebate is based on the reduction in the customer's demand, the customer knows in advance of its investment what the financial impact of participating in the DSM program will be.

On the other hand, the demand reduction coincident with the system peak is often only known with equal precision via data logging after the measure(s) are installed. Therefore, the customer has to install the measure before knowing what the customer rebate is going to be. This creates a market barrier to participation in the programs, which is overcome with HECO's

[28] See Section 226-18(a)(1) of the Hawaii Revised Statutes ("HRS").

proposal. HECO also notes that, based on the benefit/cost ratios provided on August 24, 2006, as well as the participant benefit/cost ratios revised on November 3, 2006, the TRC test results for the C&I DSM Programs remain above 1.00. See Exhibit A to 11/3/06 filing (which revises Exhibit 10) at 3-5; Exhibit B to 11/3/06 filing (which provides alternative results based on a different allocation of benefits among the programs) at 7.

4. AFRNC and PAYS PV Programs

RMI contends that, "Unless the Commission intends to promptly identify a third party program administrator for this purpose, HECO should be directed to promptly develop two additional DSM programs including an affordable housing residential new construction ("AFRNC") program and a 'Pay-As-You-Save' ("PAYS") low income solar water heating and photovoltaic program." RMI OB at 24. HECO opposes RMI's additions for several reasons.

HECO generally opposes RMI's additions because RMI has failed to adequately describe the programs' design details. Indeed, beyond making general suggestions, RMI has yet to propose specific "programs". See, e.g., RMI OB at 24-25.

With respect to the AFRNC addition, HECO particularly objects to RMI's proposed financing method. RMI argues for the creation of "a program specifically for developers of affordable housing that contains the same provisions as the RNC but also explicitly provides for a revolving loan package to pay for the remaining incremental costs of new efficiency measures not covered by incentives. These incremental costs would then be paid back from the customer's bill savings over time." RMI OB at 24; see also RMI FSOP at 44; Response to HECO/RMI-IR-118.

In other words, RMI seeks to finance its AFRNC program with a revolving loan package akin to PAYS for affordable housing. This arrangement, however, would essentially create "regulatory assets," whereby the utility's customers would own equipment, the underlying debt for which would be kept on the utility's books. See Tr. (8/29) at 277 (Hahn). The creation of regulatory assets should generally be avoided. See id. Significantly, as indicated in its FSOP, HECO has removed the utility financing options for the CIEE Program in order to avoid associated regulatory requirements that increase the program cost to the utility. See HECO OB at 80. HECO is also removing the utility financing option for the CICR program.[29]

Mitigating further against RMI's proposed financing scheme, HECO's experience reveals there has not been a market breakdown excluding low income customers from access to financing in these types of projects, such as might justify RMI's revolving loan proposal. See Tr. (8/29) at 286 (Hee). Moreover, affordable housing is eligible under HECO's proposed RNC Program, which includes a Hawaii BuiltGreen whole house design concept. See HECO OB at 107-11.

HECO opposes RMI's proposed PAYS addition for other reasons. The PAYS concept primarily targets retrofit installations of energy conservation measures ("ECM") rather than new construction. In new construction, the first cost of ECMs is less of a barrier because new construction is typically financed through construction loans and subsequently through mortgage loans, which reduce the initial cost and spread costs over time.

Further, the PAYS program targets residential solar water heating. A PAYS program was mandated by Act 240 of the 2006 Hawaii Legislature. RMI would have the Commission "use this docket to implement Act 96 [sic] and extend the PAYS program to include solar photovoltaic ("PV") as well, in combination with the AFRNC program." RMI OB at 25. However, as RMI recognized in its FSOP, the legislature did not include PV in Act 240. In fact,

[29] Note: HELCO has proposed a grant program (REEEPAH) in its rate case, which does not involve utility financing. However, RMI is not proposing a similar program.

Act 240 very specifically applied PAYS to solar water heating only.[30] At the panel hearings, HECO expressed its belief that under Act 240, the PAYS program would be separate and distinct from the REWH program, while noting that the financing arrangements for the program had yet to be resolved. See Tr. (8/29) at 325-27 (Hee). HECO is currently working on developing its PAYS program and expects to file a tariff with the Commission by the end of the year, as mandated by the Act. Finally, as discussed earlier in this Reply Brief, PV is clearly beyond the scope of this proceeding. RMI's PV proposal is thus misplaced, and RMI's proposed additional programs should not be approved in this Docket.

5. REWH and RNC Program Incentives

HSEA contends that the $5 credit paid to customers who participate in the Tank and Timer Program should be eliminated. HSEA contends further that the existing developer rebates for High Efficiency ("HE") water heaters should be eliminated or decreased. HSEA bases these contentions on its mistaken belief that the REWH and RNC incentives are "misaligned" with HECO's overall DSM goals. See HSEA OB at 6. HSEA's contentions are unwarranted. Thus, HECO supports the continuation of the $5 credit as well as the rebates for HE water heaters.

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[30] The relevant portion of Act 240 states:

> (a) Solar water heating systems are a renewable energy technology that uses solar collectors placed on roofs to heat water. These systems decrease reliance on imported oil used to generate electricity to heat water because they use less energy than the electric hot water heating systems replaced.
>
> The legislature finds that the up-front cost of installation is a barrier preventing many Hawaii residents from installing solar water heating systems. The legislature further finds that the renewable energy technologies income tax credit and electric utility rebates have not been enough of an incentive to overcome these up-front costs, especially for rental housing and homes in need of retrofit for these important energy-saving devices.
>
> The purpose of this section is to authorize the public utilities commission to implement a pilot project to be called the "solar water heating pay as you save program".
>
> (b) The public utilities commission shall implement a pilot project to be called the "solar water heating pay as you save program" . . . .

In the RNC Tank and Timer program, developers are offered an incentive to install an 80 gallon or larger high efficiency water heater with a load control device. Customers, or the eventual homeowners, are offered $5 per month for allowing HECO to use the load control device to turn off their water heaters during HECO's peak demand period of 5:00 p.m. to 9:00 p.m. HECO T-11 at 51. Since program inception, HECO has encouraged the installation of over 5,000 "tank and timers". These measures contribute 2.8 MW of peak load reduction and 1,500 MWh of annual energy savings. See HSEA/HECO-FSOP-4. Notably, HECO has found Tank and Timer locks to be more successful than solar water heating systems at keeping water heaters off during peak periods. See HECO OB at 115-16. Without the $5 per month credit, customers would have no incentive to agree to have their water heaters turned off, and the program rules allow customers to opt-out of the program at any time.

Moreover, HREA notes that, in 2005, 23.1% of Tank and Timer participants had converted to solar water heating systems. See HSEA OB, Appendix 1. In the panel proceedings, HECO estimated that customers in the natural market upgrade to solar systems about 20% of the time. See Tr. (8/29) at 356 (Block). HSEA's data thus suggests that participation in the Tank and Timer Program – and its associated $5 monthly credit – may actually facilitate, rather than undermine, conversions to solar water heating systems.

HSEA's contention that the existing rebates for HE water heaters should be decreased is also unjustified. Since program inception, HECO has encouraged the installation of over 4,000 additional HE electric water heaters without the load control device. These measures contribute 161 kW of peak load reduction and 743 MWh of annual energy savings. See response to HSEA/HECO-FSOP-5.

Solar water heating systems are not always compatible with new developments, and the array of energy-efficient water heating DSM measures provides developers with beneficial alternatives to standard-efficiency water heaters. See HECO OB at 115. Without meaningful alternatives, developers with projects not suited to solar water heating tend to install standard water heating systems. See Tr. (8/29) at 359-60 (Block). Therefore, providing customers with a variety of energy-efficient options promotes market penetration of energy-efficient DSM measures in a manner consistent with HECO's overall DSM goals. See id. at 360.

Hence, given HECO's current reserve margin shortfall, it would be imprudent to discontinue or decrease the incentives for HE water heaters or tank and timers. It would likewise be imprudent to eliminate the monthly tank and timer credit.

D. COST-EFFECTIVENESS OF DSM PROGRAMS

1. HECO's Position

The portfolio of energy efficiency DSM Programs, and the individual programs, should be approved based on the results of the benefit-cost tests, the non-qualified benefits of the programs that are not captured by the tests, and customer equity considerations. See HECO OB at 53-62, as well as discussions of individual programs at 67-127.

In its Final Statement of Position filed June 1, 2006 ("FSOP"), HECO provided updated DSM program measures, costs, energy and demand savings impacts,[31] benefit/cost ratios, and utility compensation amounts in Exhibits 7, 8, 10, and 12, which superseded the corresponding information that was included in its rate case application filing. HECO also updated certain DSM program design parameters.

In its response to CA/HECO-IR-9 filed July 1, 2006, HECO provided updated Exhibits 7, 8, 10 and 12. In discussions with RMI with respect to the updated exhibits, certain errors and

[31] For example, energy rates used to estimate customer bill savings were updated to reflect the more recent fuel oil price projections shown in Exhibit 12. Since the model only accepts one energy rate per program, the updated energy rates reflect $60/bbl LSFO fuel.

omissions in the spreadsheets included in Exhibits 7, 10 and 12 to the IR response were identified. As a result, on August 24, 2006, HECO filed a revised response to CA/HECO-IR-9 and revised Exhibits 7, 10 and 12. The revisions are summarized on page 2 to the revised IR response. As a result of these revisions, Exhibit 13 to HECO's FSOP also needed to be updated. HECO filed workpapers to CA/HECO-IR-9 revised Exhibit 7 ("revised Exhibit 7") on August 28, 2006. The exhibits included in the August 24, 2006 revised response to CA/HECO-IR-9 supersede the previously filed versions of these exhibits.

The Consumer Advocate contended that there were certain "flaws" in the calculation of the benefit/cost tests. CA OB at 54-55, citing FSOP at 74-77. The alleged flaw in the TRC test turned out to be a misunderstanding.[32] The flaw in the Participant Cost ("PC") Test involved inclusion of customer incentive payments in the program costs, which are not costs directly incurred by the participants. This flaw has been corrected in Exhibits A and B to the November 3, 2006 filing. Exhibit A corrects the PC Test results included in the tables on pages 61 and 62 of the Companies' Opening Brief.

In addition, as discussed below, HECO has provided an alternative calculation of the benefit/cost ratios based on an alternative method of allocating the avoided cost benefits of the portfolio of energy efficiency DSM programs among the programs. The results of this alternative calculation are included in Exhibit B to the November 3, 2006 filing.

The IRP Framework requires that the cost-effectiveness of DSM programs be analyzed from varying perspectives (e.g., utility cost perspective, rate impact measure perspective, participant impact perspective, societal cost perspective and total resource cost perspective).

In general, HECO evaluates the cost-effectiveness of a DSM program or portfolio of

[32] CA OB at 54-55.

programs based on benefit/cost ratios for the Participant, Utility Cost ("UC"), Total Resource Cost ("TRC"), and Rate Impact Measure ("RIM") tests. For the purposes of HECO's DSM programs, the cost-effectiveness tests follow the California Standard Practice Manual: Economic Analysis of Demand-side Programs and Projects.[33] The benefits include the net present value of the generating capacity and energy costs avoided by the DSM Programs. The costs included in the tests are direct program and/or participant costs.

The standard cost-effectiveness tests do not include non-quantifiable benefits such as customer equity, environmental and cultural benefits, and the contribution to the Renewable Portfolio Standards ("RPS").[34] The overall determination of cost-effectiveness in the IRP process, however, should take into account all of the goals and objectives of IRP (including the availability of non-quantifiable benefits, the impact of the programs on the utility's financial integrity, supporting Hawaii's State energy objectives, and the rate impacts of the programs).

The TRC perspective is the primary perspective the Commission looks at in reviewing DSM programs. See Re Kauai Electric Division of Citizens Utilities Co., Docket No. 94-0337, Decision and Order No. 15733 (August 5, 1997) at 17. In addition, impacts on non-participants, as well as participants, should be considered in determining utility incentives to customers, which are paid for by all customers.

In general, HECO's position is that DSM programs should have positive net benefits according to both the UC and TRC test perspectives to be considered "cost-effective". Moreover, the non-quantifiable benefits of DSM programs identified in the IRP process should also be considered. Therefore, while the results of all of the tests should be examined, programs

[33] See, e.g., Re Integrated Resource Planning, Docket No. 6617, Decision and Order No. 4630 (May 22, 1992) at 3.

[34] A fifth cost effectiveness test (which is considered to be a variant of the TRC Test), the Societal Cost Test, requires the quantification of social costs, but it is difficult to quantify such costs, and the quantification is generally contentious.

should not necessarily have to pass all of the cost-effectiveness tests in order to be implemented.

The benefits in the UC and TRC Tests are the avoided supply costs of energy and demand for the periods when the DSM measure or program being tested results in a load reduction. The UC benefit/cost ratio is equal to the ratio of the total discounted benefits (i.e., the net present value ["NPV "] of the avoided supply costs of energy and demand) to the total discounted program costs (i.e., the NPV of the program costs incurred by the utility, including the incentives paid to customers). The TRC benefit-cost ratio is equal to ratio of the total discounted benefits to the total discounted utility and participant costs (i.e., the NPV of the costs incurred by the utility and participants, taking into account tax credits received by participants). In the TRC Test, the incentives paid to customers are "transfer" costs (i.e., the incentives increase the utility's cost, but decrease the participant's cost).

There are different economic effects of the DSM Programs on participants and non-participants. Those differences occur because participants receive DSM program rebates for their financial investment in eligible energy conservation measures, and benefit from lower energy bills that result from energy savings. Program costs are recovered from both participants and non-participants, and both participants and non-participants receive the long-term energy and capacity deferral benefits that result from the DSM programs. HECO recognizes that the difference in economic effects exists and has intentionally developed a wide-ranging array of DSM measures under its existing and proposed DSM programs (and has budgeted funds to market those measures) in order to provide the large majority of customers with opportunities to participate.

2. Alternative Allocation of Avoided Cost Benefits

RMI recommends that the Commission "make an interim finding, subject to ongoing review, that HECO's proposed portfolio of energy efficiency programs is cost-effective based on a preponderance of sufficient albeit imperfect evidence." RMI OB at 5-6, 25-27.

The cost-effectiveness of the Energy Efficiency DSM programs was assessed by comparing the costs avoided as a result of the implementation of the programs against the program implementation costs. The avoided costs were estimated by calculating the difference in costs (capacity and energy) between a "Future EE DSM" (or "base") resource plan, which included the DSM programs, and a "No Future EE DSM" (or "alternate") resource plan, which excluded the DSM programs. See revised Exhibit 12 at 1-3.

As explained in revised Exhibit 12, the avoided costs were estimated from base and alternate plans under a "Scenario A," which included the specific assumptions described in the Exhibit. The avoided costs are sensitive to the assumptions, and a change in the assumptions would produce different avoided cost results. The assumptions used in Scenario A, and some of their associated uncertainties, were summarized in HECO's Opening Brief at pages 58 to 59.

The benefit/cost analyses require that avoided costs be determined for each program. The accepted method for doing this has been to calculate avoided capacity and energy costs for the portfolio of energy efficiency DSM programs and to allocate the total peak and energy savings resulting from all of the programs among the individual programs based on the estimated peak demand and energy savings attributable to each program.

In Exhibit 12, submitted in response to CA-IR-9 (revised on August 24, 2006), HECO provided energy and capacity costs avoided by its portfolio of proposed energy efficiency programs. As indicated in Exhibit 12, the avoided costs were based on the deferral of a coal unit and were used to develop DSM program cost-effectiveness test results measured by benefit/cost ratios. This is the same method used throughout the implementation of the DSM programs since

1996.

RMI accepted the calculated NPV for the entire portfolio of energy efficiency programs, but raised questions about the appropriateness of the benefit/cost ratio results for individual DSM programs. Specifically, RMI disagreed with the method HECO used to allocate the benefits of energy and demand savings to each program. See RMI OB at 28-29.

The avoided costs benefits arise primarily out of the assumed deferral of a 180 MW coal unit from 2015 to 2024. This results in high avoided capacity costs during those years, but negative avoided energy costs (because the coal unit would have displaced higher cost oil-fired kWh had it not been deferred).

To address this concern, HECO committed to do an alternative calculation, in which the avoided capacity costs were limited to the value of a proxy combustion turbine ("Proxy CT"). Tr. (8/29) at 475 (Williams); see RMI OB at 28-29. In such a calculation, the difference between the avoided capacity costs for the coal unit and the Proxy CT are added to the avoided energy costs, so that total avoided costs remain the same.[35] The calculation and explanation of the alternative avoided cost allocation calculation were filed on November 3, 2006.

In the alternative calculation of avoided capacity costs, HECO determined the deferral benefits of a Proxy CT unit instead of a coal plant. In order to preserve the overall energy plus capacity net present value benefits from the coal plant, the alternative avoided energy costs were derived as follows:

> (1) The difference between the annual avoided capacity and fixed O&M costs for the Proxy CT unit and the annual avoided capacity and fixed O&M costs for the coal plant was calculated.

[35] The alternative avoided cost calculation seeks to preserve the overall energy plus capacity NPV benefits at the portfolio level, but reallocates the benefits between capacity and energy. In other words, this alternative calculation is a different method of allocating the costs avoided by the portfolio of energy efficiency programs, but is not a different avoided cost. (The resource plan supported by the Company is the one that includes the coal plant. The use of the Proxy CT was simply to explore the impact of different avoided costs on the cost-effectiveness of the proposed DSM programs.)

(2) This difference was added to the annual avoided energy costs for the coal plant (as shown in Attachment 4).

Thus, the sum of the 2006 through 2025 annual avoided capacity and fixed O&M costs from the Proxy CT plus the alternative annual avoided energy costs equals the sum of the 2006 through 2025 annual avoided capacity and energy costs for the coal plant. However, now the annual allocation of capacity and energy avoided costs increases the value of the energy savings benefits of the DSM programs.

The resulting alternative avoided capacity and energy costs were used to derive alternative benefit/cost ratios for the individual proposed energy efficiency DSM programs, as shown in Exhibit B (pages 7-17) to HECO's November 3, 2006 filing. Exhibit B used the levelized rates for 2006-2025 for the purposes of estimating end effects.

The results of the TRC, UC and PT tests for the seven energy efficiency DSM programs were as follows:[36]

	Benefit/Cost Ratios		
DSM PROGRAM	TRC Test	UC Test	PC Test
CIEE	1.28	2.56	5.03
CINC	1.13	2.05	4.69
CICR	0.75	2.97	2.66
ESH	2.39	4.53	5.16
REWH	0.58	0.99	2.10
RNC	1.49	2.28	3.48
RLI	4.96	2.41	NA
Total	**1.22**	**2.42**	**3.92**

The results of the benefit/cost tests for the energy efficiency programs are shown in Exhibit A (11/3/06) on page 1.

The results of the tests using alternative avoided capacity and energy costs are as

[36] For illustrative purposes, the calculation of DSM program cost-effectiveness includes utility compensation Alternative No. 2 as proposed by HECO on page 79 of its FSOP.

follows:[37]

Cost Effectiveness Results -- 20-YEAR PLANNING HORIZON (2006-2025)
Alternative Avoided Cost WITH 15% of Program Costs

Program	B/C Ratio		
	TRC	**UC**	**PC**
CIEE	1.66	3.30	5.03
CINC	1.44	2.61	4.69
CICR	1.10	4.38	2.66
E$H	1.56	2.96	5.16
REWH	0.51	0.87	2.10
RNC	0.84	1.28	3.48
RLI	4.31	2.10	NA
TOTAL	**1.24**	**2.47**	**3.92**

3. Consumer Advocate's Alternative Approach

The Consumer Advocate, in its Opening Brief, now claims that it does not understand why there is a coal unit in the resource plan. CA OB at 56-57. The resource plan includes a coal unit, because a coal unit was included in the preferred IRP-3 Plan. See HECO Integrated Resource Plan (2006-2025) ("IRP-3 Plan") filed October 28, 2005 in Docket No. 03-0253. The coal unit provided fuel diversity, and was also cost-effective in the high fuel cost scenario analyzed in the IRP-3 process. Under the updated planning assumptions introduced in the 2006 AOS Report, the need date for the coal unit moved up in time. The Consumer Advocate did not make any information requests, or ask any questions at the panel hearings, about the resource plan scenario used to calculate the updated avoided costs when it had the opportunity to do so.

The Consumer Advocate also includes an "alternate approach" to the calculation of avoided costs for DSM programs for the first time in its Opening Brief, which it suggests would yield more "stable" results. CA OB at 57-59.

As defined in the Commission's avoided cost rules, "avoided costs" means the

[37] See Exhibit B (11/3/06).

"incremental or additional costs to an electric utility of electric energy or firm capacity or both which costs the utility would avoid by purchase from the qualifying facility." H.A.R. §6-74-1.

For firm capacity resources, avoided costs are determined using the Differential Revenue Requirements ("DRR") method, in which the utility's revenue requirements for its base resource plan are compared to the utility's revenue requirements (on a discounted present value basis) for an alternate resource plan in which another resource (such as EE DSM programs or an IPP facility) is allowed to defer or replace the utility's deferrable supply-side resources. In Hawaii, the utility's resource plan generally is that developed pursuant to its IRP process, taking into account any updates based on more recent planning assumptions and forecasts. The difference in the utility's costs between the base and alternate plans represents the costs that the HECO Utilities can avoid with the non-utility generator alternative. See, e.g., Order No. 15187 (November 25, 1996), Docket No. 94-0079 ("Order No. 15187"), at 8.

If the base plan costs are higher than the alternate plan costs, the difference between the base and alternate plan costs represent those costs avoided by the utility. Likewise, if additional costs are incurred in the alternate plan, this results in a reduction to avoided costs.

The DRR Method of calculating long-term avoided costs has been used in determining the avoided costs for previous power purchase proposals. For example, this methodology was examined extensively by the Commission and the other parties involved in HECO's application for approval of the AES-Barbers Point, Inc. ("AES-BP") and Kalaeloa Partners, L.P. ("Kalaeloa") power purchase contracts in Docket Nos. 6177 and 6378, respectively.

The Commission explained the use of the DRR method as follows in Order No. 15187 (page 8):

> In calculating avoided cost, the differential revenue requirements methodology is applied. Under this methodology, a base utility plan and

> a QF-in plan . . . are compared. The difference in the utility's costs between the base and QF-in plans represents the costs that HELCO can avoid with the non-utility generator alternative.

The DRR methodology is one of three generally accepted methodologies to determine avoided costs. The other two avoided cost methodologies are the peaker method and the proxy plant method. The peaker method is a marginal cost approach. In applying this method, avoided capacity costs are set equal to the cost of a new peaking unit (or lower if there is surplus capacity) and avoided energy costs are determined as system marginal energy costs. The proxy plant method identifies the next unit that would be added by the utility. Both avoided capacity and energy costs are set based upon the cost of the proxy unit.

The DRR methodology is often referred to as the most accurate methodology for determining avoided costs because it is the only methodology that explicitly develops a long-term plan for a base case and an alternate case and forecasts revenue requirements for each case. The principal strengths of the DRR methodology are that, for each alternative resource it examines, it develops a detailed assessment of the impact of the alternative resource upon the utility plan and a comprehensive assessment of the cost (revenue requirements) impact of the alternative resource to the utility.

The DRR method has always been used to calculate avoided costs for HECO's DSM programs. It is the most accurate method, and takes into account the supply-side resources that would be deferred or displaced by the DSM programs, rather than hypothetical peaking units. In addition, the peaker method tends to overstate avoided energy costs, since it ignores the energy displacement value of new, lower energy cost, supply-side resources. Moreover, since avoided costs are used in determining the benefits used in the benefit/cost ratios and in the achieved DSM program benefits used to set shareholder incentives, overstating avoided costs of DSM programs was not deemed to be desirable.

4. Solar Water Heating System Life

HSEA recommends that the Commission adopt a 25-year system life in considering the cost-effectiveness of solar water heating systems. HSEA OB at 6-7. HECO, on the other hand, continues to support a 15-year system life. See HECO OB at 44. The 15-year system life was based on data from ASHRAE, the American Society of Heating, Refrigeration, and Air Conditioning Engineers. HECO nevertheless recognizes that with some maintenance, a system's life could probably be longer. However, HECO does not have a study to show that the system life of solar water heating systems is anything other than 15 years. If HSEA were to furnish HECO with more information, HECO would consider it. Finally, due to the time value of money, HECO points out that a system with a life of 30 years is not twice as cost-effective as a system with a life of 15 years. See Tr. (8/29) at 437-38 (Block).

E. SWAC PROPOSAL

HECO supports HREA's efforts to establish a cost-effective SWAC system on Oahu. If HREA is successful, HECO's position is that the SWAC program should be eligible for DSM program rebates under the CICR Program. See HECO OB at 138-40. HREA contends, on the other hand, that SWAC systems would be more appropriately implemented within the CIEE Program.

Contrary to HREA's contention, the CICR Program was designed to encompass equipment: (1) not specifically identified in any of the other prescriptive DSM programs; (2) not widely available in the market; and (3) with which HECO lacks previous experience documenting the measure savings. See HECO OB at 139. SWAC has never been specifically identified in any of HECO's prescriptive DSM programs, and because SWAC has never been available in Hawaii's air conditioning market, HECO has never had a chance to document the measure's savings. SWAC is therefore precisely the kind of DSM measure that belongs in the CICR Program.

Moreover, the CICR Program's provisions requiring independent third party review of projects projected to cost more than $25,000 enhances the validity of impact results from more complicated projects, such as SWAC. See id. Moreover, as HECO noted in its Opening Brief, the benchmark-based rebates paid under the High Efficiency Cooling component to the CIEE Program range between $20 and $55/ton, significantly less than what HREA is requesting. HREA's request to place SWAC in the CIEE Program should therefore be denied.

HECO's preliminary analysis under the CICR Program indicates that the SWAC program rebate would be between approximately $150 and $230/ton. See HECO OB at 141. HREA, however, argues for a SWAC program rebate of $500/ton. This argument mistakenly relies upon HREA's assumptions regarding interconnection costs and comparisons with cost-differentials for other technologies. In DSM program design, one of the key considerations utilized to set customer rebate levels is to set them at levels that are necessary to motivate customers to adopt cost-effective DSM measures (i.e., move the market). Accordingly, rebate levels are not necessarily determined on the basis of participant costs or avoided capacity value. See HECO OB at 140-41.

HREA has failed to establish that the existing CICR rebate level is inadequate to move the market. Thus, without further justification, raising the CICR rebate level at this time would be imprudent, as it would expose ratepayers to the risk of having to pay more than is necessary to customers who are already being sufficiently encouraged to install SWAC systems. See HECO OB at 141. Moreover, the Consumer Advocate notes that a proposal for a $500 per ton rebate for a 25,000 ton central SWAC system would cost consumers $12.5 million, more than 60% of HECO's total proposed budget for program expenses in this proceeding. CA OB at 65 n.40.

Based on actual inflation since the its inception in the mid-1990s, and the likelihood of large projects in the future, HECO has proposed to increase the CICR Program's rebate limit from $250,000 to $350,000. See HECO OB at 40. Although HREA asserts that the rebate limit should be doubled to $500,000, See HREA OB at 20, HREA has failed to demonstrate why such a dramatic increase might be necessary. HECO thus supports limiting the increase in CICR rebates to $350,000.

The Consumer Advocate suggested two possible options, in which the Commission either: (1) state that the history of customer incentives/rebates available to qualifying demand-side programs can serve as a guide to DSM developers as they project potential customer incentives in their economic analyses, or (2) requires the utility to now identify a schedule of customer incentives/rebates that the Commission expects will require the utility to provide in relation to future DSM programs and their budgets. CA OB at 66. The Consumer Advocate recommends that action on the SWAC proposal be deferred and considered in the development of HECO's fourth IRP, which is to be filed on or about the fourth quarter of 2008 and would include a five-year action plan for 2009 through 2014. CA OB at 66.

III. DSM MARKET STRUCTURE

A. INTRODUCTION

The second Statewide Energy Policy Issue is: What market structure(s) is the most appropriate for providing these or other DSM programs (e.g., utility-only, utility in competition with non-utility providers, non-utility providers)?

The issue of market structure revolves around the question of whether DSM programs are more effective if administered by a utility or a non-utility program administrator. Program administration consists not only of program implementation (i.e., the delivery of the energy efficiency measures to the customer), but also includes the design, monitoring and evaluation, and overall oversight of the program. HECO OB at 147.

HECO supports the development of a hybrid market structure. The application of market structure criterion led HECO to the conclusion that HECO should continue to administer the CIEE, CINC, CICR[38], REWH[39], and RNC[40] programs. HECO acknowledged that, in certain situations, HECO did not possess a clear advantage over other providers in delivering energy efficiency DSM programs to HECO's customers. Under certain limited circumstances, a third-party DSM administrator might provide opportunity for more cost-effective DSM program delivery to certain under-served customer segments, because certain customer segments are difficult to reach with existing DSM program options. See discussion below. In addition, load management programs should remain utility administered programs.[41]

The list of criteria HECO used to determine which proposed or new (as yet unidentified)

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[38] Utility administration of the CIEE, CINC, and CICR programs as applied to large commercial and industrial customers in Schedules J, PP, PS, and PT, take advantage of the utility's local market and technical expertise and the depth and nature of the customer relationships that HECO has developed over years of serving these customers by responding to their business needs. HECO OB at 159.
In addition, HECO has (1) established professional relationships with architects, engineers, and developers that seek out HECO's expertise in energy efficient technology, and (2) an account management process in place that provides a relationship with larger customers. See HECO OB at 159. These advantages over a third-party administrator that the utility already possesses translate into the ability to communicate and effect energy efficiency in an established environment of trust and credibility. This environment of trust is likely to result in greater rates of DSM program acceptance by the customer than if a new administrator were to appear in the market and have to establish these same relationships. HECO OB at 159-60.

[39] On balance, utility administration of the REWH program that targets retrofit residential solar water heating benefits from the long-standing relationships established with the solar contractors. HECO's solar water heating program has created a disciplined market served by reputable contractors installing standard, well designed, and reliable systems. However, competitive market forces are still at work, as each contractor sets its retail price at the level determined by demand and supply. HECO OB at 160.

[40] The RNC program benefits from HECO's long-standing relationship with all major housing developers such as Gentry Homes, Haseko, D.R. Horton, and Castle and Cooke. Over the years HECO has established its credibility with the housing developers and they have come to trust HECO concerning the new construction area. HECO OB at 160-61.

[41] Load management programs, including demand response programs, provide load reductions when called for and activated by the utility. The load must be available for interruption shortly after being notified of a possible load control event and/or must be dropped immediately when HECO determines that an emergency situation exists. HECO OB at 162.

DSM programs should be administered by the utility, and which by a third-party, contained the following: (1) Differential Expertise; (2) Depth and nature of customer relationship; (3) Cost of financing for programs funded with direct financing; (4) Cost structure to administer program; (5) Economies of scale or scope; (6) Tight linkage to system operations; (7) Efficiency loss in transition and continuity; (8) Regulatory costs, ease of administration, and resource requirements; and (9) Potential overlap or conflicts between administration of programs. See HECO OB at 151–53. (The list of criteria was developed based in part on a paper published by the Regulatory Assistance Project in May 2003 [a copy of which was attached as Exhibit 5 to HECO's FSOP]. HECO OB at 151.)

HECO developed a matrix that evaluated the DSM programs and customer segments that are included in its DSM program proposal in this docket against the above criteria. HECO OB at 154. (a copy of the matrix was attached as an exhibit to HECO's Opening Brief). The evaluation identified: (1) Some programs and customer segments as possibly being more effectively served under third-party administration; (2) Others being more effective under utility administration; (3) Some programs or customer segments that would be, on balance, more effectively served under utility administration; and (4) One program (the Interim Energy Solutions for the Home Program) that should be administered by the utility in the near term, but could transition to third-party administration at a later time. HECO OB at 171.

The determination of whether <u>new</u> DSM programs should be administered by the utility or third-party administrator should be made within the IRP process, which is likely to be the source for many of these programs, using the market structure criteria. If a new program is not developed within the IRP process the administrator should apply the criteria objectively and report the results in the program application to the Commission for approval. HECO OB at 163.

MECO has been successfully working with the small communities on Lanai and Molokai to deliver energy efficiency to these geographically isolated areas. Based on its experience, MECO recognized that without the assistance of the utility, these communities may be neglected under a third-party administrator. Therefore, MECO should be permitted to keep the Lanai and Molokai DSM programs under its administration, unless the Commission believes that those two islands can gain from an alternative administrative structure. HECO OB at 162.

B. POSITIONS OF THE OTHER PARTIES/PARTICIPANTS

1. RMI

RMI recommends that the Commission adopt a hybrid market structure. RMI OB at 7-8. In addition, RMI recommends that the Commission provide the third party administrator with enough flexibility to offer innovative financing programs, make decisions rapidly, and provide enough funding to allow for a successful start-up. RMI OB at 1.

RMI and HECO agreed on the use of a hybrid structure, and have both provided criteria to determine which programs should be implemented by the utility and which should be implemented by a third party administrator. RMI concurs with HECO that the programs for the hard to reach sectors should be given to an independent third party administrator. RMI OB at 7.

HECO considers the following customer segments likely to benefit from third-party administration because they are difficult to reach with DSM program options:

1. Residential low-income customers typically unable to participate in DSM programs because they cannot afford the first cost necessary to install energy savings measures.
2. Programs (such as the Pay As You Save program) that will benefit renters of individually metered housing units, both single family and low rise residential buildings.

3. Low-rise multi- unit housing buildings (condominiums and apartment buildings) that are master metered.

4. Small commercial customers in Schedule G. HECO OB at 154-55.

Also included among the programs that could be administered by a third-party are residential Energy Star appliance marketing programs[42] and the Interim Energy Solutions for the Home ("ESH") program approved by the Commission in Interim D&O No. 22420[43]. See HECO OB at 155-56. In addition, another program category that could be administered by a third party are those DSM programs that install energy efficiency measures using non-ratepayer provided funds (e.g., charitable or government funding) that results in a financing cost that is significantly lower than can be found in the market (e.g., City & County of Honolulu Solar Roofs, Low-Income Solar Loan Program, Maui Solar Roofs Initiative, Department of Energy, U.S. DOE Million Solar Roofs Initiative, United States Department of Agriculture ("USDA") Rural Utilities Service Grant, Big Island Solar Roofs Program, Island of Hawaii Million Solar Roofs ("MSR") Partnership). See HECO OB at 156-57.

Should the Commission adopt HECO's recommendations and decide that some or all of the aforementioned types of DSM programs should be administered by a third party, HECO requested that it be allowed to compete for the implementation of these programs at its discretion. HECO may decide to compete if it determines that there is an opportunity to cost-

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[42] While these programs are directed at the general residential customer segment, which is not a particularly hard-to-reach customer segment (in contrast to those identified above), HECO does not possess any significant advantage over other parties that may be interested in pursuing this new program. Administration of this program by another party may also result in innovative marketing skills or approaches that can improve upon the expected customer participation relative to a utility-administered program. HECO OB at 155.

[43] The Interim ESH program involves point-of-sale rebates for approximately 180,000 compact fluorescent lamps ("CFLs") on an annual basis. HECO already has a significant level of experience with the local CFL market via its pilot program implemented during the 4th quarter of 2005 and has begun the implementation of the approved interim program by entering into discussions with its manufacturer, distributor, and retail trade allies. If this interim program is determined by the Commission to be most effective under third-party administration, HECO will transition this program over to the third-party administrator in the manner approved by the Commission. HECO OB at 155.

effectively deliver energy efficiency into these customer segments. If HECO were to be awarded the implementation of any of these programs, it would report to the third-party administrator based on the terms of the negotiated mutually agreed upon service contract. HECO OB at 158.

Even if HECO decided not to compete for program implementation in these areas, HECO would like to continue its participation in the process to ensure the effective delivery of energy efficiency measures in a collaborative manner with the Commission, Consumer Advocate, third-party administrator, and vendors (e.g., HECO could assist the Commission with the development of standards, and/or in defining appropriate post-installation evaluation and measurement methods). HECO OB at 158.

The combined package of third-party administered programs and customer segments, along with the participation of the utility, could form an effective nucleus for a strong community-based initiative aimed at improving energy efficiency in geographically targeted areas around the state.[44] HECO OB at 158.

RMI points to HECO's load management programs as an example of why utility involvement in DSM program administration makes sense. See RMI Final SOP, at 16 (stating that load management programs that incorporate direct control of customer loads are probably most effectively planned, designed, and implemented by utility management). Load management programs that incorporate direct control of customer loads in tight coordination with utility system operation needs are probably most effectively planned, designed and implemented by utility management. RMI OB at 6.

[44] The third-party administrators would report to the Commission or could report directly to HECO if the Commission finds the burden of supervising the administrator to be too great. The funding for the third-party administrators could be collected through the DSM surcharge and could be disbursed by the utility directly to the third-party administrator or on the directions of the Commission. This is similar to the process done in California. HECO OB at 153-54.

2. <u>HSEA</u>

HSEA recommends that the utility retain the administration of the REWH and RNC programs. HREA maintained that these programs are the most successful of their type in the country, and that there are no other administrative models – utility, third-party or hybrid – with which to compare them. HSEA OB at 6, 15-16.

In addition, HSEA stated that its members are most concerned about the continuation, continuity, continual improvement, and expansion of these critical DSM programs, particularly the REWH and RNC programs as they relate to solar water heating system sales and installations. Incremental program improvements are more important to the majority of HSEA members than wholesale changes in administration or the outright elimination of utility involvement in the solar industry. HSEA OB at 11.

HSEA believes that the basic continuity and consistency of the current portfolio of DSM programs over the past ten years is in large measure responsible for the measured impacts and successes to date. HECO's solar water heating programs, for example, contrast very favorably with one designed by the Sacramento Municipal Utility District ("SMUD") in the early nineties. The SMUD program was poorly conceived, constantly changing, confusing to the public and contractor alike, had no long-term contractor support, and subsequently faded away to irrelevance. At present SMUD offers a $1,500 rebate, has three participating contractors, and very few subscribers. More important to industry participants, the failure of the SMUD solar program has negatively impacted both our industry's image as well as solar water heating system sales in the greater Sacramento area for years. HSEA OB at 13.

On balance, HSEA finds that HECO's DSM programs have benefited to date from clarity of purpose, basic consistency, predictability and have achieved support among both participants and ratepayers. In light of HSEA member concerns regarding DSM program continuity and consistency, plus the magnitude of the reserve margin shortfall and the potential disruption, delays, and loss of staff and infrastructure during any transition to a new market structure, HSEA favors the continuation of utility management of these programs, with the proviso that certain hard to serve customer classes may well benefit from limited third party administration of targeted programs. HSEA OB at 14.

HSEA shares the concern that a third party administrator, potentially a "wholesale" level low bidder, may simply focus, for example, on classically "economic" programs (i.e., those that look most cost-effectiveness under the traditional forms of measurement and may disregard customer class or other program equity issues). HSEA OB at 7. HSEA recommends that the Commission provide for the retention of the retail competition that now exists in the delivery of REWH and RNC program services. HSEA wants to make clear that retail competition is not synonymous with the wholesale level competition that may ensue should a third-party administrator be chosen for some or all of the DSM programs. Retail competition provides ratepayers with a broad choice of contractors, products, and price levels. Retail competition among numerous participating DSM contractors has benefited the ratepayer, Hawaii's primarily small business contractor infrastructure, and HECO. HSEA OB at 7, 22.

HSEA also agreed with HECO and RMI that a third party administrator may be the best choice to administer targeted programs that provide solar water heating systems and other measures to underserved categories of ratepayers including low income homeowners, renters, and the multi-family apartment and condo communities. HSEA OB at 14.

3. **KIUC, DOD and TGC**

KIUC believed that it should continue to administer energy efficiency efforts on the island of Kauai. See KIUC OB at 13-14; KIUC Final SOP at 10-14. TGC noted that it should administer gas industry DSM programs whenever such programs are required by the Commission. See TGC OB at 8-13; TGC FSOP at 5-10.

DOD did not make a specific recommendation concerning whether an independent third party should administer some or all of the DSM programs, but is not opposed to a third party administering DSM programs, provided the appropriate safeguards are in place. DOD OB at 7, 8.

4. Consumer Advocate

The Consumer Advocate contends that responsibility for the administration of (i.e., administering, designing, implementing, monitoring and evaluating) the energy efficiency and DSM programs for HECO, HELCO, and MECO should be given to a non-utility third-party administrator, such "as the public benefits fund administrator", authorized by Act 162, Session Laws of Hawaii 2006 ("Act 162"). CA OB at 9.

The Consumer Advocate provided a detailed, reasoned basis for its initial position that Hawaii's electric utilities should retain their established role as administrators of DSM programs in Hawaii. Moreover, the Consumer Advocate's initial position is fully supported by the detailed analyses done by HECO and RMI of the factors for and against continuation of utility administration of such programs.

The Consumer Advocate's new position that administration should be transferred to a third-party is not supported by such an analysis, and fails to even respond to its own earlier analysis or to the analyses of HECO and RMI. Moreover, the Consumer Advocate's stated reasons for switching its position are without merit.

The Consumer Advocate's Initial Position

In its FSOP filed June 1, 2006, the Consumer Advocate recommended that "the Commission retain the established market structure in which Hawaii's electric utilities retain the role as the administrators of DSM programs in Hawaii." CA FSOP at 8, 17.

In reaching this conclusion, the Consumer Advocate relied upon the discussion of issues related to DSM program administration published by the Regulatory Assistance Project ("RAP") in May, 2003 in a report entitled "Who Should Deliver Ratepayer Funded Energy Efficiency." CA FSOP at 17-18. A copy of the RAP report was filed as Exhibit 5 to the Companies' FSOP filed June 1, 2006. As noted by the Consumer Advocate, the RAP report examines the merits of alternate approaches to DSM program administration (i.e., as provided by electric utilities, third-parties and government agencies) from the standpoint of four basic criteria:

> 1. Compatibility with broader public policy goals. The subcriteria offered include harmony with financial interests, integrated resource portfolio, resource acquisition, environmental improvement, economic development, energy efficiency market transformation, sustainability of effort over time (funding stability and institutional stability);
>
> 2. Accountability and oversight. The subcriteria offered include "how is budget set," "who participates in program development (opportunity for public participation)," "are measurement and evaluation metrics integral part of program design (program and process evaluation)," "how are results verified," frequency of reporting and protocols for periodic program review;
>
> 3. Administrative effectiveness. The subcriteria offered include efficient, non-redundant administrative costs, budget competency, ability to acquire and retain high quality staff, flexibility to adapt programs to evolving market conditions/opportunities, ability to target funds geographically, and local options for program design; and
>
> 4. Transition issues. The sub-criteria offered include start up costs of a new organization and the smooth transfer of program responsibility.

CA FSOP at 18, citing RAP Report at 11.

Based on the RAP report, the Consumer Advocate noted that the utilities that achieved high levels, of investment in DSM measures in the early 1990's had three things in common:

1. clear and sustained regulatory policies existed relative to DSM activities;

2. proper incentives were in place including internal rewards for corporate achievement in energy efficiency; and

3. stakeholders supported the DSM programs.

CA FSOP at 20, citing RAP Report at 17. Second, RAP concluded that "the more robust ratepayer funded energy efficiency programs are less the result of administrative structure per se, than the clear and consistent commitment of policy makers." Id.

The RAP Report also makes the following additional noteworthy points:

> 1. The single strongest feature favoring utility implementation of energy efficiency is that the utility has the relationship with the customer (usually a relationship of trust) and is knowledgeable about customer's individual energy use.
>
> 2. A second beneficial feature of utility program administration is the compatibility with integrated long run resource acquisition.
>
> 3. A third beneficial feature of continued utility administration is retention of the existing infrastructure, knowledgeable staff and relationships within the energy services professional community as well as relationships with distributors. Once a utility has developed a staff and infrastructure to develop and deliver cost-effective efficiency programs there is reason to be cautious about taking steps to dismantle that infrastructure by assigning the duties elsewhere.

RAP Report at 16-17.

In support of its position at that time, the Consumer Advocate also attached its PSOP, which provided a detailed analysis supporting the conclusion that the Commission should retain the established market structure in which Hawaii's electric utilities retain the role as the administrators of DSM programs in Hawaii:

> The Consumer Advocate recommends that the Commission retain the "market structure" in which Hawaii's electric utility companies have central roles as program administrators of DSM programs. The Consumer Advocate anticipates that allowing the utility to retain responsibility for the administration of DSM programs will enable the utilities to draw upon the services currently available from various segments of the existing competitive demand-side services industry to secure any needed

assistance in designing, implementing, monitoring and evaluating demand-side programs. Thus, third-parties are quite likely to continue to be engaged in the design, implementation and evaluation of DSM programs authorized by the Commission. The overall responsibility for DSM program administration should, however, continue to reside with the utilities for the following reasons.

CA PSOP at 24.

In its PSOP, the Consumer Advocate cited the following reasons:

1. Electric utility companies necessarily have a central role in identifying resource needs, developing resource plans to meet those needs, and securing resources that are responsive to those needs. Introducing another party (i.e., a third-party provider) to these processes presents a number of challenging issues, and ultimately could threaten a utility's ability to fulfill its obligation to serve.

2. Changing Hawaii's approach to providing DSM programs could require statutory changes and Commission orders (and may require a new regulatory construct by which the activities of the third-party provider would be overseen).

3. Changing Hawaii's approach to providing DSM programs could disrupt the delivery of demand-side programs at a critical time.

4. Changing Hawaii's approach to the administration of DSM programs could introduce difficult problems in cost-recovery.

5. In Hawaii, where the electric systems are not interconnected, there is a growing demand for electricity and limited sites are available for new generation, thus Hawaii's electric utilities should have a strong incentive to pursue cost-effective DSM programs in order to fulfill their obligation to serve.

CA FSOP at 24-32.

According to the Consumer Advocate, "[t]he primary reason for recommending that Hawaii's electric utility companies be allowed to continue providing the DSM programs is that they have an obligation to serve. In order to fulfill this obligation, each utility must be able to develop plans for how best to cost-effectively meet the forecasted load that results from customer demands." CA PSOP at 25

The Consumer Advocate noted that the introduction of a third-party DSM administrator would present challenges because of the many ways that such action would create discontinuities in utility planning processes. The utility's load forecasting processes would somehow have to accommodate the fact that a third-party would be responsible for achieving energy- and demand-savings. Either the utility would have to (a) develop its own forecast of such savings (perhaps with incomplete or imperfect information from the third-party DSM program administrator), or (b) accept forecast savings developed by the third-party DSM administrator (perhaps with little opportunity to test the reliability of those savings forecasts). "Either situation may result in decisions that do not ensure the provision of reliable service at a reasonable cost." CA PSOP at 26.

The Consumer Advocate also maintained that "[p]articularly challenging would be the process by which potential incremental supply- and demand-side resources are identified, then selected for inclusion as components of an 'integrated' resource plan. Here conflicts seem quite possible." CA PSOP at 26.

Further, the Consumer Advocate contended that "[u]ltimately, these issues translate into important questions regarding an electric utility company's obligation to serve. For example, what path should be followed if a utility's planning processes were effective, but a reliability problem materializes as a consequence of poor information (or poor performance) on the part of a third-party DSM administrator? Should the Commission absolve the utility of its service obligations? These and many other important, practical questions would have to be resolved before third-party DSM administrators could reasonably be allowed to supplant utility DSM administrators." CA PSOP at 27.

The Consumer Advocate's Change of Position

The Consumer Advocate has reconsidered its initial recommendation and now supports the non-utility third-party DSM market structure approach, and now contends that a non-utility third-party administrator:

> (1) is consistent with the market structure contemplated by the Legislature and the Governor when Act 162 was signed into law on June 2, 2006;
>
> (2) removes the perceived inherent conflict between (a) a utility's desire to generate revenues and income by increasing sales and rate base, and (b) energy efficiency measures that serve to decrease sales and defer the need for additional plant investment; and
>
> (3) could reduce the costs of implementing energy efficiency measures by eliminating the need to recover lost margins on an annual basis and, more importantly, provide an incentive for such implementation.

CA OB at 27.

The Consumer Advocate's stated reasons for switching its position are without merit. First, the legislature had already passed the bill that was signed into law as Act 162 at the time that the Consumer Advocate submitted its FSOP, in which it supported continued utility administration of DSM programs.

According to the Consumer Advocate, "the enactment of Act 162 signals that the Legislature and the Governor believe that third-party administration of energy efficiency and DSM programs in Hawaii constitutes the preferred market structure for DSM program administration in the State." CA OB at 28. However, in its own FSOP, the Consumer Advocate explicitly noted that "[t]he legislation that was ultimately passed (i.e., Senate Bill 3185, S.D.2, H.D.2, C.D.1) left the determination of these matters [i.e., alternate market structures for the delivery of demand-side services in Hawaii] to the Commission." CA FSOP at 17 n.11. That is, the legislature, with support from the utilities, the Commission and others, passed enabling legislation so that the Commission could decide the matter in this proceeding, as opposed to legislation that would have removed the Commission's discretion and required a shift to third-party administration.

The FSOP did note that "HECO continues to seek recovery of lost margins and shareholder incentives. If HECO persists in this position, it seems quite possible that the balance could shift in favor of third-party administration of DSM programs. Presumably, third-party DSM program administrators would have no need for lost margin recovery. In such case, they may be able to implement a given set of DSM programs at much lower cost than could a utility. Over a period of years, the ratepayer savings that may result could be substantial." CA FSOP at 20 n.15.

None of the Companies' proposals included full recovery of lost margins between rate cases. Moreover, the Companies now have eliminated their request for a mechanism that, in effect, would recover some part of lost margins between rate cases. In addition, the Companies have substantially reduced their request for utility compensation, and note that any administrator would require some for of compensation over and above recovery of costs.

With respect to the "inherent conflict", the same alleged conflict existed when the Consumer Advocate concluded, after a reasoned analysis of the arguments for and against utility administration, that the utilities should continue to administer the DSM programs.

Moreover, the Consumer Advocate also states in its Opening Brief that, when the utility is in need of additional plant, but is unable to install the plant, "the utility has an incentive to maximize the implementation of, energy efficiency measures to ensure that there is sufficient generation to reliably meet the utility's customers' energy needs. This is especially applicable in Hawaii where each utility is not interconnected to another utility, there is limited land available for siting new generation, and competing interests for the land that is available." CA OB at 31. Thus, the Consumer Advocate concedes that the utility does have an incentive to offer DSM programs.

Further, in arguing against a hybrid market structure, the Consumer Advocate contends that such a structure is not consistent with the regulatory obligations of a utility to serve, and "it is important for the utility to retain responsibility for implementing energy efficiency measures in hard to reach areas." CA OB at 30. Logically, this would mean that any transfer of DSM program to a third-party administrator would not be "consistent with the regulatory obligations of a utility to serve . . . ."

HECO also demonstrated why it should continue to be allowed to administer some DSM programs. The Companies have been successful in their energy efficiency efforts under the existing market structure. From 1996 through 2005, the Companies' energy efficiency programs have reduced customers' consumption of energy by 2.4 million mwh and reduced peak demand by 66 MWs. The annual amount of energy saved through HECO's DSM programs has increased each year for the past three years, and HECO is nationally recognized for installing the highest number of solar water heaters in the nation. See HECO OB at 148-49.

The analysis of the transfer of all DSM programs to a third-party administrator should include the following considerations: (1) accountability and the obligation to serve, (2) program constancy, consistency, and continuity, and (3) cost-effectiveness. See HECO OB at 164-68. A review of these considerations demonstrates that administration of all DSM programs should not be transferred to a third-party administrator.

With respect to accountability and the obligation to serve, energy efficiency DSM is an important component of HECO's portfolio of resources, that complements conventional supply-side resources, renewable resources, distributed generation, and load management, for meeting HECO's obligation to serve. DSM programs play an important role in ameliorating HECO's existing reserve capacity shortfall situation. HECO's IRP plan relies on the load reductions from

DSM programs to meet the long-term projections of demand. HECO questioned whether a non-utility program administrator would have the same imperative, or the same accountability or responsibility to achieve the load reductions as the utility. If a third party administrator were to administer and implement DSM programs then the utilities would need to rely on the DSM impact projections from the third party administrator for IRP planning. Since a crucial resource is no longer under the utilities' control, should the utilities' obligation to serve be excused? If the utility is still obligated to serve all customers in its franchise area, then the utility would need to implement additional contingency planning and mitigation measures in the event the third party administrator does not achieve its projected amount of load reduction. HECO OB at 164-65.

In the early 1990s, the California PUC ("CPUC") was prepared to assign DSM to an independent, non-profit organization. However, before it could do so, the 2000/2001 California energy crisis hit, and the CPUC administered the DSM programs through the utilities during the crisis. In 2005, as a result of the lessons learned during the crisis, the CPUC returned the DSM programs to the utilities.[45] HECO OB at 165.

If a third party were to administer the DSM programs, that third party should be subject to oversight by the Commission similar to the oversight requirement to which HECO is held.[46]

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[45] The CPUC's decision (Decision 05-01-055, January 27, 2005, Rulemaking 01-08-028, Order Instituting Rulemaking to examine the Commission's Future Energy Efficiency Policies, Administration and Programs) provided the following reasons for reassigning the programs to the utilities:

1. The utilities must be responsible and accountable to meet their obligation to serve.
2. Energy efficiency is a cost-effective resource that can be used to meet electricity demand.
3. In its resource planning, the utilities should not be required to adopt the DSM plans of others.
4. The CPUC must have authority to hold the administrator of the DSM programs accountable.
5. There would be significant start-up costs and transition time lags associated with a change in program administration.
6. There were concerns about the ability of a third party to carry out the necessary fiduciary responsibilities.

[46] With respect to its DSM programs, HECO is required to:

HECO OB at 166.

With respect to program constancy, consistency and continuity, DSM programs are most effective when the market sees the objectives for energy efficiency as clear, consistent, and continuous. HECO's DSM program objectives include: (1) Deliver energy savings and peak demand reductions; (2) Contribute to the attainment of the Renewable Portfolio Standard; (3) Provide all classes of customers the opportunity to participate; and (4) Do so cost effectively. HECO OB at 166-67.

These objectives have been clear, consistent, and continuous since the DSM programs were instituted in 1996. Customers, distributors, vendors, and building design professionals that participate in these programs are aware of this. To change the programs at this time, when they have been working very effectively, may create substantial uncertainty and jeopardize the program infrastructure that has been developed over the past 10 years. This could result in lost opportunities to install energy efficient measures and in resources being expended in an unproductive manner. HECO FSOP at 34.

Use of a third party to implement DSM programs would require a period of transition between utility and third-party DSM program administrator.[47] Duplicate costs during the transition are unavoidable (e.g., in the transition there would have to be two parallel efforts for at least part of the time to get the new programs established: two sets of offices, staff, programs and program materials). Once the transition is complete there could still be delays due to the third

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1. File two annual reports (the Annual DSM Program Accomplishments and Surcharge report in the March timeframe, and the Annual DSM Program Modifications and Evaluation Report in the November timeframe),
2. Request Commission approval of new DSM programs or modifications of existing programs,
3. Request Commission approval of budget modifications,
4. Independently verify and confirm energy and demand savings, and
5. Explain/support these requests in response to inquiries from regulators. HECO OB at 166.

[47] HSEA notes that a "best case transition" might take three years. HSEA OB at 15-6 & n.20, <u>citing</u> RAP Report at 20.

party working out the "bugs" of its program provisioning (e.g., learning curve inefficiencies, vendor responsibility scoping, request-for-proposal processing, and contract negotiations). All of this will increase cost and, more seriously, delay the acquisition of demand-side resources, which HECO is depending on to meet a substantial portion of its future capacity needs. HECO's proposal of a hybrid approach allows the third party to focus on new programs, and reduces duplicative resources needed during transition. HECO OB at 167, citing HECO FSOP at 34-35; Tr. (8/30) at 572-78 (Violette).

Mr. Violette testified that he is aware of situations when DSM implementation has gone from utility implemented to third-party implementation that has resulted in "substantial delay" in achieving the DSM goals. A factor that contributed to the decline in the performance of the DSM programs was the departure of utility employees who implemented and administered the DSM programs, despite best efforts to retain the employees. Tr. (8/30) at 573-77, 80-84 (Violette). HECO has experienced this type of situation (e.g., HECO's DSM Director left the company and one of the reasons mentioned by the former DSM Director was Interim Order No. 22420 which, among other things, ordered that HECO could no longer accrue the recovery of lost margins and shareholder incentives. Tr. (8/30) at 584-85 (Hee).

Substantial care would have to be exercised in the selection of a third-party administrator, given the critical role of energy efficiency DSM programs in meeting State and utility energy objectives. The Companies have proposed that the Commission select third-party DSM administrators through a competitive procurement process. HECO OB at 153-54.

Mr. Violette testified that when requests for bids for third-party administration of DSM programs have issued, there has not been a large number of entities that have responded to those requests for proposals.[48] Mr. Violette testified that recent experience has shown that choices for a third-party administrator have been constrained due to the small number of responses the entities have received.

When there have been responses for the administration of DSM programs, the bidders have generally bid on the easier-to-reach sectors (i.e., the "low-hanging fruit"). The bidders did not generally bid on broad wide-ranging DSM programs. See HECO OB at 172; Tr. (8/30) at 592-95 (Violette).

Moreover, a bid process might not produce the broad spectrum of DSM programs that is desirable. See Tr. (8/30) at 715-57 (Bollmeier, Reed). In general, the experience with bidding for DSM programs has been that the utility could provide the DSM programs at a lower cost than the bidders. Mr. Oliver referred to a study conducted by Lawrence Berkeley Laboratory in the 1990s that concluded that the utility's own DSM lighting programs were lower cost than the bids that came in for most of the programs. HECO OB at 172.

Another concern identified at the panel hearings was the potential for a duplication of efforts, and resulting customer confusion. See Tr. (8/30) at 584-85 (Hee); 586-89 (Violette). If a third-party is permitted to provide some DSM programs, then there should be open channels of communication and effective management with the customers and between the utility and third-party administrator in order to mitigate any confusion that the customer may have by having multiple entities offering and maintaining the customer's energy efficiency efforts. HECO OB at 158.

With respect to cost-effectiveness, HECO has demonstrated that it has been successful in

[48] One of the reasons for the lack of a large number of choices for a third-party administrator is that most of the entities want to be a contractor to a utility as opposed to being a regulated administrator of DSM programs. These entities view the profit as being in the direct delivery of the DSM programs, and not in the commission-regulated administration of the DSM programs. HECO OB at 171.

delivering cost-effective energy efficiency programs under the existing market structure. In 2004, HECO was able to deliver energy efficiency for less than 24 cents per kwh saved, which was lower than the costs incurred by Efficiency Vermont, the third-party administrator in the state of Vermont generally recognized as the model for non-utility program administration. HECO OB at 168.

5. HREA and LOL

HREA and LOL suggested that the Commission adopt a third-party DSM market structure as an outcome of the Energy Efficiency Docket. See HREA FSOP at 4; see also LOL FSOP at 4-7. LOL also recognized, however, that HECO should continue to administer load management programs. See Tr. (9/1) at 1060 (Curtis).

HREA supports the establishment of a Public Benefits Fund ("PBF") and a PBF Administrator for the implementation of "energy-efficiency and demand-side management programs and services" ("PBF programs").[49] See HREA OB at 8.

HREA notes that, during the hearing, questions were raised by various parties "about whether it would be feasible to select the PBF Administrator (which was alternately referred to as a 'DSM Utility' or a 'Third Party Administrator') via a Commission-administered competitive bidding process, as proposed by HREA in its FSOP." As a result, and "[g]iven that the market pool for PBF Administrators may be 'thin' as suggested by HECO during the hearing, HREA requests that the Commission consider foregoing a competitive bidding process, as proposed by

[49] HREA believes the "PBF Market Structure" should be established and implemented to facilitate a competitive market, whereby the PBF Administrator works closely with energy service providers competing to supply DSM technologies and measures to customers and coordinates with the host utility on the PBF programs. HREA OB at 8.

HECO's role could include participation in DSM under contract to the PBF administrator and/or to HECO's provision of certain DSM programs and services deemed outside the scope of the PBF administrator. As an example of the latter, HREA stated that it could support HECO administration of DSM programs and services on the "utility-side of the meter," while the PBF administrator would administrator the DSM programs and services on the "customer-side of the meter." HREA OB at 9.

HREA in its FSOP, and proceed to appoint a PBF Administrator as authorized in Act 162. After a review of PBFs already implemented on the mainland, HREA believes the Energy Trust of Oregon serves as a good model for Hawaii to consider." HREA OB at 11, citing Exhibit A to its Opening Brief (which apparently is based in part on undocumented discussions with Energy Trust of Oregon staff after the hearing).

As previously discussed in response to the Consumer Advocate's recommendation, HECO has demonstrated that it is not appropriate to transfer the administration of all DSM programs to a third-party administrator.

In addition, HREA's proposal to have the Commission appoint a PBF Administrator is lacking in details. For example, HREA does not discuss how long it will take to accomplish selecting and appointing the third-party administrator. This process would likely be a lengthy process. In the meantime, market uncertainty will exist that threatens the constancy, consistency, and continuity of the DSM programs. This uncertainty can only disrupt DSM program delivery, make participation in the programs by customers more uncertain, and delay the customers' acquisition of energy savings and the utility's acquisition of load reductions. See HECO OB at 170.

HECO does not agree that a public benefits funds should be established. According to the July 2006 National Action Plan ("NAP"), public benefits funds are vulnerable to raiding, and funding levels are disconnected from the resource planning portfolio of energy efficiency and other resources. This is particularly a concern if the resources are not sufficient for the utilities to achieve their DSM program goals. HECO OB at 154 & nn. 75-77.

HREA also claims there are opportunities for the PBF Administrator to deliver DSM at lower administrative costs (i.e., more of the PBF could be provided to ratepayers/customers in the form of rebates and other incentives to invest in DSM measures). HREA contends that implementation of PBF Market Structure in Hawaii will result in lower administrative costs than HECO's administrative costs for DSM. See HREA OB at 8 (citing to "personal communications" with Energy Trust of Oregon) and Exhibit B.

HECO's DSM program cost structure results in low total program costs. In addition, its ratio of customer incentive payments to total program costs is higher than for Efficiency Vermont, indicating that HECO's program participants receive more "bang for the buck" in terms of an incentive to install energy efficient measures relative to Efficiency Vermont. See HECO OB at 168.

HECO and LOL are in agreement with respect to HECO continuing to administer the load management programs. The DSM program administrator is the entity that will have a central role in the administration, coordination and supervision of DSM programs. For load management programs the coordination of load management includes the crucial decision of when the enrolled load should be interrupted in order to maintain system stability. The utility is in the best position to make that decision based on projections of demand, the status of the generating units and other available resources, and the state of its transmission and distribution systems. The requirement that the loads be dropped when required by the utility necessitates the utility administering these programs. HECO OB at 162.

The need for the utility to be the load management program administrator does not necessarily mean that it has to market and enroll customers into the load management programs (as differentiated from administering). Load aggregators have been known to acquire load reduction resources on behalf of utilities or Independent System Operators ("ISO") in other jurisdictions. However, the decision of when to activate the resource has always been retained by the utility or ISO. HECO OB at 162-63.

IV. DSM COST RECOVERY FOR UTILITY-INCURRED COSTS

A. SUMMARY

The third Statewide Energy Policy Issue is: For utility-incurred costs, what cost recovery mechanism(s) is appropriate (e.g., base rates, fuel clause, IRP Clause)?

The seventh issue, which is specific to HECO's Proposed DSM Programs, is: "If utility-incurred costs for the Proposed DSM Programs are to be included in base rates, what cost level is appropriate, and what the transition mechanism for cost recovery will be until the respective utility's next general rate case?"

The appropriate cost level for the energy efficiency DSM programs proposed by HECO is addressed in Part III of the Opening Brief. This part of the Reply Brief addresses the mechanisms that should be used to recover those costs, both before and after the next rate case.

HECO's DSM programs were developed under the Commission's IRP Framework. The Commission, in its Framework for Integrated Resource Planning, adopted in 1992, recognized the need for the recovery of DSM program costs: "The utility is entitled to recover all appropriate and reasonable integrated resource planning and implementation costs." Paragraph III.F.1 of the IRP Framework provides that the utility is entitled to recover its integrated resource planning and implementation costs that are reasonably incurred, and identifies four recovery mechanisms. IRP Framework ¶III.F.1.

DSM program costs currently are being recovered partly through base rates and partly through the DSM component of the IRP Clause. With respect to incremental DSM program costs, program costs are expensed and recovered annually through the IRP Clause, in the Residential, and Commercial & Industrial DSM Adjustments. This mechanism was developed in the collaborative working group that developed the DSM cost recovery and incentives structure for the initial DSM Programs approved in 1996. See HECO OB at 173-74.

HECO's position coming into this proceeding was that, in the next rate case (presuming the Energy Efficiency Docket decision and order is received before the next rate case), utility-incurred costs and utility incentives for its DSM Programs should be recovered through base rates, with a DSM Reconciliation Clause, as proposed in HECO's 2005 test year rate case. See HECO OB at 174-75.

In the informal submittal of preliminary statements of position in the March 2006 timeframe, in subsequent settlement discussion meetings with the parties/participants, and at the panel hearings, many of the parties/participants preferred recovery of program costs through a DSM surcharge, similar to the mechanism currently in effect, rather than recovery through base rates. For example, the Consumer Advocate changed course from the DSM Stipulations, and recommended continued partial recovery of DSM expenses through a surcharge. Tr. (8/31) at 795 (Hahn).[50] In its FSOP, HECO stated that it was willing to explore the DSM surcharge option with the parties/participants further during the course of this proceeding. See HECO OB at 175-76.

At the panel hearings, HECO stated that, if released from the constraint imposed by the DSM stipulations, HECO is willing, and even prefers, to recover program costs (and utility compensation) through a surcharge, as long as HECO is granted sufficient flexibility with respect to its annual DSM program budgets. Tr. (8/31) at 778-79, 782 (Hee). To a certain extent, this would facilitate (1) reconciliation of revenues received to recover estimated costs that are

[50] The Consumer Advocate proposed to continue the current DSM cost recovery mechanism, under which incremental DSM program costs are recovered through a surcharge, but the labor costs for HECO employees who are dedicated to the DSM programs are included in base rates. Tr. (8/31) at 782-83, 784-86 (Hahn).

initially included in the surcharge, and actual costs, and (2) tracking of costs expended on the programs. See Tr. (8/31) at 779-82 (Hee). HECO also stated that all program costs should be included in the surcharge, if that cost recovery mechanism is used, to account for changes in the number of in-house employees dedicated to the programs. Tr. (8/31) at 783-84, 756 (Hee).[51]

The Consumer Advocate (and others) favored continuing to reflect the surcharge amount separately on customer bills. See, e.g., Tr. (8/31) at 795 (Hahn) (since the surcharge on bills provides a "signal" to customers to participate).

B. POSITIONS OF THE PARTIES

RMI's position is that the utilities and any third party administrators should be entitled to recover the reasonable and approved expenditures for DSM programs through a volumetric tariff implemented as a surcharge on utility bills that is explicitly subject to ex poste reconciliation. RMI OB at 3, 9-10, citing FSOP at 17-20.

RMI opposes the base rate recovery of DSM costs. RMI OB at 4, 21. RMI recommends that the costs of ratepayer funded DSM programs should primarily be recovered through a surcharge mechanism subject to adjustment and reconciliation. According to RMI, DSM expenditures collected in base rates should be limited to labor expenses for DSM related positions that, as of the date of the beginning of the rate case test year, have already been established and filled for a period of time sufficient to demonstrate that the positions are necessary and ongoing in nature. RMI OB at 3, 9-10.

In addition, according to RMI's Opening Brief:

> During the panel hearings the Moderator asked RMI for comments regarding the gaming potential associated with surcharge recovery identified in an entry in the evaluation matrix provided by RMI in RMI Exhibit C. After some discussion of this

[51] The costs for Account Managers, who facilitate their customer's adoption of DSM measures, would remain in base rates. Tr. (8/31/) at 786, 787 (Hee).

> matter the Moderator suggested that RMI get together with HECO and the Consumer Advocate to <u>pin down what needs to happen to minimize the potential for gaming associated with surcharge and base rate recovery of DSM expenses</u>. Although RMI tried to defer to the other parties on this matter the Moderator left this initiative with RMI and RMI agreed to oblige. (Tr. at 802-803) Neither HECO nor the Consumer Advocate agreed or disagreed with this proposition on the record at the panel hearings.

RMI OB at 29 (underlining added).

The potential for "gaming" is minimized by the Companies' proposal to recover all DSM Program expenses through the DSM surcharge and the continued filing of the Annual Program Accomplishments and Surcharge ("A&S") Report. The recovery of all DSM Program expenses through the DSM surcharge eliminates the possibility of also recovering those costs through base rates. The filing of the A&S Report, which includes an itemization of DSM Program costs for Commission and/or independent evaluator review, minimizes the risk of recovering inappropriate costs. HECO T-10 at 50; FSOP at 39-40; HECO OB at 64, 172-77.

The Consumer Advocate's position is that, during the transition from the current market structure to the proposed non-utility third-party administration of energy efficiency and DSM programs, HECO, HELCO, and MECO should be allowed to recover utility incurred energy efficiency and DSM program costs through the existing IRP surcharge mechanism. All reasonable utility incurred costs to administer the energy efficiency and DSM programs should be recovered through a surcharge mechanism (for non-recurring costs such as customer rebates, equipment costs, etc.). CA OB at 9, 10.

HSEA recommends that DSM program costs should continue to be recovered through a billing surcharge mechanism. HSEA OB at 7-8, 16.

DOD favors including a reasonable estimate of program costs (including incentives paid to customers) in base rates. DOD OB at 1-2. DOD also supports a periodic adjustment to "true-up" actual program-related expenditures (i.e., direct, identifiable, out-of-pocket expenses), above or below the amount included in base rates, subject to appropriate reasonableness reviews. DOD OB at 2-3; see Tr. (8/31) at 788-89 (Brubaker).

V. UTILITY COMPENSATION

A. SUMMARY

The fifth statewide energy policy issue is: "Whether DSM incentive mechanisms are appropriate to encourage the implementation of DSM programs, and, if so, what is the appropriate mechanism(s) for such DSM incentives?"

The eighth issue, which is specific to HECO's Proposed DSM Programs, is: "Whether HECO's proposed DSM utility incentive is reasonable, and should be approved, approved with modifications, or rejected?"

These issues necessarily involve two sub-issues: (1) Should electric utilities receive compensation (over and above recovery of prudently incurred program costs) for DSM programs; and, if so (2) what DSM utility incentive mechanism should be implemented?

Utilities can and should be compensated for successfully delivering energy efficiency DSM programs to their customers. There are two primary reasons why regulatory commissions have recognized that compensating utilities for successfully implementing energy efficiency DSM programs is beneficial and in the public interest:

(1) Compensation mechanisms put energy efficiency DSM options on a more level playing field with supply-side options; and

(2) Incentive regulation is more effective and requires use of less regulatory "resources" than "command-and-control" regulation.

In addition, it is critically important to recognize that all rate-setting policies embody incentives of one type or another. The elimination of lost margins and shareholder incentives would simply substitute one set of incentives for another. An appropriate incentive is one that does not reward distortions of investment, makes the least cost plan the most profitable for the entity that is responsible for implementing that plan (in this case, the utility), and is clear and direct. Eliminating all incentives for DSM would be counter to the public good, and would effectively establish incentives that reward the utility to direct its efforts toward supply-side alternatives.

B. HECO'S PROPOSAL

In its 2005 test year rate case, HECO proposed recovery of a DSM Utility Incentive through base rates. The basis for proposing a base rate mechanism was HECO's stipulations with the Consumer Advocate, approved by the Commission (the "DSM Stipulations")[52], in which HECO agreed to not seek the recovery of lost margins and shareholders incentives through a surcharge mechanism in the next rate case and thereafter. HECO OB at 174-75.

The mechanism proposed in the rate case consisted of two components, including the recovery of the fixed cost shortfall due to sales lost as a result of implementing energy efficiency, and the recovery of a percentage of program costs, representing a return similar to that earned by other companies involved in the service industry. Furthermore, because this recovery was to be included in base rates, HECO proposed including a levelized amount of recovery, with a performance-based DSM reconciliation process between rate cases. The test year estimate of the cost of the DSM utility incentive was $8.8 million. Of the total incentive, $2.7 million was the return on program costs, and $6.1 million was for the recovery of the fixed cost shortfall. HECO OB at 178.

[52] See HECO OB at 2-3, and Exhibit "C".

Based on discussions with the other parties in the settlement meetings in this docket, HECO acknowledged that both the compensation mechanism and the level of compensation proposed in the rate case required re-evaluation. Thus, HECO has been open to suggestions from the other parties as to the mechanism and level of utility compensation for aggressively pursuing DSM programs, and has made alternative proposals with respect to utility compensation for implementing DSM programs. HECO OB at 178.

The first alternative is a shared savings mechanism as the basis for utility compensation for the administration and aggressive pursuit of energy efficiency. HECO's first alternative does not include the recovery of fixed cost shortfalls between rate cases. The shortfalls are recovered through base rates in a general rate case when the impact of energy savings resulting from DSM programs is included in the test year sales estimate. HECO OB at 178-79, 211-12.

The second alternative included the recovery of the shortfall in fixed costs combined with 15% of program costs (excluding the program costs for the load management programs). However, the shortfall in fixed costs recovery would be limited to one year's worth of shortfall and would not be cumulative. HECO OB at 179, 212-13.

Under either alternative, the compensation would not be paid to HECO unless the Company attained at least 80% of the energy efficiency KW load reduction goal. Once the 80% threshold attainment level is reached, HECO would then be eligible for compensation as determined by the mechanism. Further, under either alternative, the amount of total compensation would be capped at $4.0 million before taxes. HECO OB at 179, 213.

At the panel hearings, HECO indicated that its current proposal is the first alternative, under which utility compensation would be based on 5% of the net benefits of the energy efficiency DSM programs, based on the modified utility cost test. The utility would receive no compensation if it achieved less than 80% of the annual megawatt goal, there would be a cap on the incentive of $4 million before tax per year, and the compensation would be paid on a prospective basis, trued-up in the following year for actual achievements. Under this mechanism, HECO confirmed that it was not asking for lost margin recovery outside of a rate case. HECO OB at 179, 215.

By this proposal, HECO proposed to reduce its share of the savings by half, from 10% to 5%. Based on the avoided costs provided in revised Exhibit 13 (rev. 8/24/06) to HECO's FSOP, HECO estimated that a 5% share of the net benefits would be approximately $3.0 million annually assuming that the utility continues to be the administrator for all DSM programs.

The advantages posed by the shared savings mechanism include: (1) it is performance-based, such that higher energy savings and load reductions, and lower program costs result in greater levels of compensation; (2) the value of benefits is linked to actual system needs; and (3) the mechanism is currently in use and familiar to the Commission, Consumer Advocate, and the Companies. HECO OB at 212 & n.105.

The EPA Report identified several key factors characterizing utility incentives:

> (1) Net DSM benefits are often a key input into incentive mechanisms.
>
> (2) Where incentives are based on net DSM benefits, the incentive is calculated based on every unit of TRC achieved (not just above a target).
>
> (3) Utilities have a minimum performance level that they must exceed before they are eligible for an incentive award. This minimum performance level is typically set at some level below the utility's DSM target.
>
> (4) The metric for the minimum performance level is often different than the metric upon which the incentive payment is based.

EPA Report at 31-32.

Based on those key factors, the EPA declared that: "The alternative DSM incentive mechanism offered by HECO appears more reasonable when compared to its initial proposal. The moderate share of savings proposed combined with a performance target appear favorable when compared to an approach based on a percentage of expenses with no performance target." EPA Report at 37-38.

C. POSITIONS OF THE PARTIES

1. RMI

RMI's position is that "[t]he utility and third party administrator should be rewarded for reaching a threshold level of performance with incentives that are no greater than the utility shareholder earnings on ratebased supply side costs that the portfolio of DSM programs displaces." RMI OB at 3, 12-16.

RMI proposed a specific utility compensation mechanism in Exhibit B (pages 14-19) of its FSOP, which was tied to avoided investment costs, and assumed that decoupling was in place so that lost margin recovery did not have to be taken into consideration. See RMI OB at 16: Tr. at 942-43 (Freedman); Response to HECO/RMI-IR-142.

RMI now recommends that the Commission adopt HECO's most recent revised incentive proposal identified at the panel hearings, with one modification. However, RMI recommends that this proposal "be modified to provide a further limit on the incentive level to no more than the utility earnings opportunities foregone by implementing DSM programs in lieu of supply-side ratebased investments." RMI OB at 3-4.

RMI's support for utility incentives is based on the same two fundamental considerations identified by HECO, and recognized by NARUC, the National Action Plan, and regulatory commissions in other jurisdictions that support DSM programs as a fundamental utility resource:

(1) "At a fundamental level, utility management has powerful institutional

prerogatives to achieve returns for shareholders. Demand side programs will be severely disadvantaged in terms of management resources and focus unless the programs offer profitable opportunities and are not solely a source of foregone earnings potential. RMI's proposed incentive places DSM on par with supply side measures in this respect. This approach is consistent with the principles regarding incentives enunciated in the Commission's IRP Framework and in the Hawaii RPS statute." RMI OB at 13.[53]

(2) RMI suggests that the important practical regulatory advantages of a performance based shared savings mechanism should not be overlooked. In addition to providing the utility with a fair earnings opportunity, a positive, performance based utility incentive provides several important practical regulatory benefits by aligning the incentives to the utility with the DSM program objectives and ultimately with the interests of the utility customers:

> (a) "[A] performance based shared savings mechanism is an effective method to control utility DSM expenditures to the 'most effective minimum.'"
>
> (b) "[I]mplementing a shared savings mechanism based on ex post evaluation of utility performance would allow the Commission to permit substantial flexibility in program implementation without sacrificing accountability."

RMI OB at 13-15.

2. <u>HSEA</u>

HSEA recommends that the Commission allow reasonable and prudent performance based incentives to either utility or third party administrators to implement and manage DSM programs in Hawaii. HSEA OB at 5, 16. In addition to the recovery of all fixed DSM program costs, HSEA believes that the utility is entitled to the same level of compensation that they

[53] In its FSOP, RMI pointed out that, under traditional rate of return regulation, implementation of DSM programs could reduce a utility's sales below the levels projected in a rate case, thereby leading to an under-recovery of a utility's fixed costs. To remedy the under-recovery of fixed costs, RMI supported the establishment of incentives to encourage utilities to embrace DSM programs within their service territories. RMI FSOP at 35.

would have received by rate basing supply-side resources of similar MW magnitude. HSEA OB at 16.

3. The Consumer Advocate

The Consumer Advocate contends that incentives "are no longer necessary" to encourage the' aggressive pursuit of energy efficiency and DSM programs by a utility or third-party administrator. CA OB at 10. In support of its position, the Consumer Advocate argues that:

> (1) The incentives that were authorized by the Commission in the early 1990s were provided to encourage the utilities to embrace the concept of implementing energy efficiency measures, which was a "novel" approach at the time, as a means of meeting the utilities' customers' energy demand;
>
> (2) The IRP Framework requires the utilities to consider energy efficiency and DSM measures as a means of meeting customer demands;
>
> (3) The RPS law requires utilities to achieve a defined percentage of sales through the installation of renewable energy, which includes energy efficiency measures;
>
> (4) DSM programs do not have the same risks as traditional supply-side resources;
>
> (5) The impacts of energy efficiency programs will not cause the utility's investment and earnings potential to stagnate, because there is a continuing need to replace aged facilities, which will allow the utility to increase its depreciated rate base, and maintain or increase the utility's earnings potential;
>
> (6) Third-party administration of energy efficiency and DSM programs in Hawaii eliminates the need to provide lost margin recovery and shareholder incentives to affected utilities; and
>
> (7) "Last and most important, the Commission stated that the continued provision of an incentive to encourage utilities to pursue energy efficiency measures will be revisited."

CA OB at 39-42.

Contrary to the Consumer Advocate's belief, the appropriateness of utility compensation for successful implementation of DSM programs is not limited to the initial implementation period for such programs. There have been a number of recent decisions indicating that state regulators and national associations are revisiting DSM incentives and re-applying the same principles that helped create the initial set of incentives for DSM at utilities that became leaders in the development of energy efficiency programs. HECO OB at 189.

For instance, NARUC Board Resolutions in 2003 and 2004 indicate an increased interest in providing utilities with appropriate compensation to aggressively pursue investments in energy efficiency. HECO OB at 189-90.

The Energy Action Plan adopted on May 8, 2003 by the California PUC, the California Energy Commission, and the California Power Authority calls for "providing utilities with demand response and energy efficiency investment rewards comparable to the return on investment in new power and transmission projects". HECO OB at 195.

The July 2006 National Action Plan for Energy Efficiency ("NAP") that EPA facilitated along with the U.S. Department of Energy provided several other examples of incentive mechanisms. See NAP, Chapter 2. A copy of the NAP was attached as Exhibit A to HECO's Response to EPA Report.

The NAP was developed by a Leadership Group of 50 leading organizations representing diverse stakeholder perspectives and "is a call to action to utilities, state utility regulators, consumer advocates, consumers, businesses, other state officials, and other stakeholders to create an aggressive, sustainable national commitment to energy efficiency." NAP, Executive Summary at 6. The Leadership Group clearly saw utility incentives as a key to overcome barriers that have limited greater investment in programs to deliver energy efficiency.

One of the five recommendations made by the Leadership Group and adopted as part of the plan is to "[m]odify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments."

NAP, Executive Summary at 2. The options identified under this recommendation include providing utility incentives for the successful management of energy efficiency programs. NAP, Executive Summary at 8.

The EPA Report filed in this proceeding pointed out that there are a variety of DSM incentive mechanisms used in different states and provided examples from five states and provinces that incent their utilities for pursuing DSM.[54] EPA Report at 31-34.

In addition, the "compensation" approach to utility DSM programs is superior to the "command and control" approach. In the "command and control" approach, a regulatory commission specifies exactly what the utility should do. The commission then monitors closely subsequent actions for compliance with the commission directive. If the utility does not follow adequately the commission's order, the commission, in subsequent proceedings, can penalize the utility. A number of the jurisdictions and public interest organizations that have strongly supported DSM have explicitly recognized the superiority of the "compensation" approach to the "command and control" approach. See HECO OB at 181-86. The Consumer Advocate does not even address the issue of whether incentive regulation works better than command-and-control regulations.

With respect to whether utility compensation is warranted under the current circumstances, Dr. Violette stated that -

> it is a matter of good public and regulatory policy to provide positive incentives so that investments in suitable and effective demand-side management programs are at least as attractive to the utility as investments in supply-side options. Load growth, coupled with the time required to implement new supply-side resources, provide an incentive to a utility to pursue demand-side resources, at least in the short-run. But that does not mean that requiring the utility to accept uncompensated risks as its 'reward' for meeting its service obligation is good public or regulatory policy. That would be comparable to

[54] EPA's report entitled "EPA Comments in Docket No. 05-0069 for the State of Hawaii Public Utilities Commission" ("EPA Report") was filed July 26, 2006.

> arguing that a utility should not be compensated for costs incurred in restoring its system after a natural catastrophe, because the utility needs to restore its system anyway in order to provide service. In the longer term, the 'message' conveyed to the utility would be that it should focus its future efforts on the supply-side of the equation.

HECO OB at 197-98, quoting response to CA-IR-320 in Docket No. 04-0113.

With respect to the IRP Framework, the framework does require and always has required that utilities consider energy efficiency and DSM measures as a means of meeting customer demands. IRP Framework ¶III.F.3 provides, however, that under appropriate circumstances the Commission may provide the utility with incentives to encourage participation in and promotion of full-scale DSM programs. The Framework provides that the incentives may take any form approved by the Commission, and identifies four of the possible forms of incentives. IRP Framework ¶¶III.F.3, 3.a.[55] The existing mechanism is a "shared savings" approach.

The IRP Framework did not limit utility compensation to the initial period for implementing DSM programs. In D&O 14638, in which the Commission approved the initial C&I energy efficiency DSM programs, the Commission found that: "Shareholder incentives, when properly designed, encourage utilities to aggressively pursue cost-beneficial DSM resources. Such incentives, along with cost and lost margin recovery mechanisms, compensate the utility in part for forgoing the opportunity to invest in additional supply-side resources." D&O 14638 at 27.

The Commission also stated that: "Ideally, shareholders incentive should be based on the actual impact achieved by the DSM measures. However, for purposes of HECO's first IRP cycle, we will allow HECO to base shareholders incentive on prospective estimates of DSM measure impacts. Concerted efforts by HECO to implement DSM measures are just beginning;

[55] The IRP Framework also provides that the Commission "may terminate any and all incentives whenever circumstances or conditions warrant such termination." IRP Framework III.F.3.c. See Docket No. 6617, Decision and Order No. 11630 (May 22, 1992) at 19.

and the reduction of reliance on supply-side options in meeting the demand for electric energy is a matter of State concern. Moreover, HECO's undertaking DSM programs is not without risks - risks that are not present in undertaking supply-side resources. Uncertainties concerning load impact, participation levels, and financial community reactions are risks that are not otherwise compensated for without shareholders incentive. Thus, it is appropriate that we provide HECO with as much incentive as possible at the outset so that DSM programs may be fully implemented quickly on as wide a basis as possible."

The change expected by the Commission in subsequent IRP cycles was a change to an ex post impact basis for determining measure impacts. "We expect that after the first IRP cycle, a transition will be to an ex post impact basis in determining shareholder incentives." D&O 14638 at 34-35. That transition has already been made, and the mechanism proposed by HECO in this proceeding also is based on ex post impacts.

With respect to the third point, the Renewable Portfolio Standards ("RPS") law explicitly recognizes that utility incentives should be considered to encourage Hawaii's electric utility companies to use cost-effective renewable energy resources.

The RPS law, as amended by Act 95 (2004) and Act 162 (2006), directs the Commission to develop and implement a utility rate-making structure, by December 31, 2007, which may include but is not limited to performance-based ratemaking ("PBR"), to provide incentives to encourage Hawaii's electric utility companies to use cost-effective renewable energy resources found in Hawaii to meet the renewable portfolio standards, while allowing for deviation if the standards cannot be met in a cost-effective manner, or due to events or circumstances beyond the utility's reasonable control.[56] The implicit assumption of this provision is that the form of regulation (i.e., the regulatory regime) can favorably impact the achievement of the renewable portfolio standards. In essence, the Commission is asked to look at incentive-based regulation, as an alternative to the traditional command and control form of regulation, in which the Commission directs the utility to do certain things, and imposes penalties if those things are not done.[57]

With respect to the fourth point, both DSM and supply-side options pose risks, and it is difficult to argue that one set of risks is greater than another. Risks that utilities face when they implement DSM programs include (1) limitations on the availability of end-use market baseline data, (2) market risks (participation assumptions), (3) infrastructure risks (i.e., vendor capacity to meet the demand created by the DSM programs), and (4) performance risks (i.e., ability of equipment to improve energy efficiency). The expected savings will vary depending on the availability of market data and the characteristics of those customers that choose to participate in the program (and these participants may differ from those assumed to participate when planning the program). Attainment of participation rates might be more difficult than anticipated, requiring a change in mode of marketing and/or the marketing message. HECO OB at 184, 185-86.

The Consumer Advocate's fifth point also misses the mark. The utilities' earnings do not

[56] PBR was the only mechanism identified by name in the law for consideration by the Commission. Performance-based ratemaking generally identifies performance criteria and incentives for exceeding targets as well as penalties for falling short.

[57] In developing and implementing a ratemaking structure to provide incentives that encourage Hawaii's electric utility companies to use cost-effective renewable energy resources to meet the renewable portfolio standards, the RPS law directs the Commission to determine the extent to which any proposed utility ratemaking structure would impact electric utility company profit margins, and to ensure that the electric utilities' opportunity to earn a fair rate of return is not diminished. In essence, the RPS law recognizes that the imposition of renewable portfolio standards, and the requirement that utilities take actions such as implementing energy efficiency measures to achieve those standards, create certain risks for the utility.

have to "stagnate" for the effects of successful energy efficiency DSM programs to negatively affect the utility's profitability between rate cases. And since HECO is no longer proposing to recover lost margins between rate cases, it is doubly important for a fair utility compensation mechanism to be implemented. See discussion of lost margins, supra.

With respect to the sixth point, lost margins are not a "cost" of utility-administered DSM programs that somehow disappear when DSM programs are administered by third-parties. Rather, lost margins are the result of successful energy efficiency DSM programs, whether administered by utilities or by third-parties. The impact of such DSM programs on utility sales must be recognized in setting utility rates, regardless of who administers the programs.

The Consumer Advocate acknowledged that some level of lost margins will be recovered in the rate setting process, but argues that the annual accrual of lost margins and cost recovery of such accrual should no longer be permitted. CA OB at 33 n.25. Thus, the Consumer Advocate clarified that, with third-party administration, "there will no longer be a need to provide annual recovery of lost margins associated with the implementation of energy efficiency measures between rate proceedings." CA OB at 33 (emphasis added). However, even this difference is moot, since HECO no longer is seeking lost margin recovery between rate cases.

Moreover, in the event that the Commission establishes a third-party DSM administrator, that administrator would expect to be compensated for its services at some level beyond the simple recovery of its program and administrative costs. Even a non-profit entity would be looking to enhance its financial condition to improve its ability to serve its constituents. The compensation mechanism should be transparent regardless of whether the provider is the utility or a non-utility third-party. Therefore, HECO should also be compensated as a provider of a similar service when administering DSM programs. HECO OB at 193.

With respect to the last point, the Consumer Advocate apparently equates reconsideration of incentives with elimination of incentives, although there is a nothing in the IRP Framework that suggests that incentives should be eliminated. HECO, on the other hand, has proposed to forego the recovery of lost margins between rate cases to limit its recovery of shareholder incentives, despite a nearly three-fold increase in the magnitude of its energy efficiency programs.

In denying partial reconsideration of Interim Decision and Order No. 22420, the Commission assured HECO and the parties that the Commission "did not prejudge the issues in this proceeding when it issued Interim Decision and Order No. 22420. HECO identifies two 'utility DSM incentive mechanism' issues: (1) whether DSM incentive mechanisms are appropriate to encourage the implementation of DSM programs, and, if so, what is the appropriate mechanism(s) for such DSM incentives, and (2) whether HECO's proposed DSM Utility Incentive is reasonable, and should be approved, approved with modifications, or rejected. The commission did not prejudge these issues, and in deciding these issues, the commission will consider the entire record in these proceedings, including the arguments set forth at the Panel Hearing." Order No. 22921 at 21-22.

4. DOD

DOD opposes utility incentives, because "DOD does not believe that shareholders need to receive rewards for doing what a utility is supposed to do," and HECO confirmed that it "does not require shareholder incentives in order to act professionally and pursue the appropriate combination of DSM and supply-side resources . . . ." DOD OB at 6, 7.

Both the premise for the argument and the conclusion are wrong. Expenditures for energy efficiency DSM programs are not just like other O&M expenses, and incentives are appropriate for energy efficiency DSM programs, as NARUC has recognized, as other regulatory commissions have recognized, as the NAP has recognized, and as this Commission has recognized in the past.

A utility incurs O&M expenses in providing electricity to its customers, and it is through electricity sales that the utility recovers its fixed costs, including a return of and return on its investment. (Increased sales may lead to the need for further investment, but the utility will be entitled to an opportunity to earn a fair return on that additional investment as well.)

In contrast, a utility incurs energy efficiency DSM program expenses in order to reduce the sales of its product. Reducing sales reduces the utility's profitability.[58] As Dr. Violette demonstrated, under rate of return regulation (i.e., using revenue requirements, comprised of capital, a return on capital, and variable costs), HECO will lose money (i.e., receive less net revenues after accounting for variable costs) on each kWh successfully delivered through its energy efficiency programs.[59] HECO OB at 198-99.

To the extent any incentive is found appropriate, DOD's position is that it "should be based on a careful evaluation of program performance." Also "[t]o the extent shareholders have the possibility of being rewarded for HECO performance that exceeds the expected level, they

[58] That is not the case with load management DSM programs, which generally are designed to reduce the peak load that the utility must serve, without significantly affecting sales.

[59] Under current rate making policies the utility is allowed to earn a fair return on its capital investments in generation. In contrast, when a utility promotes effective energy efficiency DSM programs, (1) revenue is reduced by more than the reduction in variable costs due to lower sales, and (2) without utility compensation, the energy efficiency programs fail to earn a return at the same time they defer those capital investments in generation upon which the utility can earn a fair return.

Energy sales are reduced from the levels that otherwise would have occurred without DSM. The reduced levels of energy use result in reduced costs to supply the energy, but also result in a larger reduction in revenue to the utility. Embedded in that revenue is not only the fair return allowed by the Commission on the utility's investment in generation, but also some contribution to the utility's fixed costs to serve its customers. Consequently, if a utility implements effective energy efficiency programs without a utility incentive, not only is there a potential foregone opportunity to invest that money in an endeavor that would produce a fair return, but it also contributes to an erosion of the utility's revenue to offset its fixed costs and maintain its level of profitability. Response to HSEA/HECO-IR-8.

should similarly be subject to some reduction in compensation, i.e., a penalty, if the performance is below expectations." DOD OB at 6-7.[60]

The Company's position is that penalties for unmet DSM targets or goals are not necessary. HECO FSOP at 41. A properly designed incentive (i.e., one that adequately rewards good performance towards well defined objectives) provides sufficient incentive as demonstrated by HECO's DSM program performance under the existing shareholder incentive mechanism. A properly designed utility incentive does not need to penalize "bad performance" because the Commission already has the ability to do so under its existing regulatory powers. Therefore, a separate and additional penalty for bad performance is not necessary. Response to CA/HECO-IR-8; see Tr. (8/31) at 855-56 (Waller).

At the hearings, DOD tried to justify having penalties on the grounds that an incentive mechanism should be "symmetric". Tr. at 854, 949 (Brubaker). Such a penalty would be triggered by a "failure" to achieve an "expected" level of performance determined in the IRP process, not by imprudence. See Tr. 855, 861, 949 (Brubaker).

Under such a proposal, the "baseline" compensation for meeting the expected performance would be zero. If performance was less than expected, the compensation would be negative. In effect, the utility would not fully recover its costs, even though the proponents of such a mechanism support full cost recovery. See Tr. 934-937 (Brubaker).

Such a position is unreasonable. If there is a penalty, it should not be triggered simply by the "failure" to meet the targeted level of performance. Any penalty should be triggered only if the utility fails to achieve a minimum acceptable level of demand or energy savings. Any other result would be unfair. See Tr. 950-51 (example provided by Mr. Hempling).

[60] See also CA OB at 42.

Falling short of the goal would not necessarily mean that the utility acted imprudently. Tr. 948 (Brubaker). The utility's ability to meet the expected level of performance would depend on matters, such as customer acceptance, that are beyond the utility's reasonable control. Thus, the utility could "fail" to meet the expected level of performance based upon matters that were beyond its reasonable control, rather than due to imprudent behavior. See Tr. 940-42 (Brubaker).

Through his follow up questions, Mr. Hempling also demonstrated the difficulty in setting the minimum "expected" performance level that would have to be met to avoid penalties (i.e., to avoid recovering less than all of the utilities' DSM program costs). See Tr. at 946-48, 951-52.

For example, a penalty should not be triggered by the "failure" to achieve a TRC benefit/cost ratio of 1.0 or greater, even though that might be the desirable outcome. If the baseline is based on a TRC ratio of 1.0, then the utility would not recover its costs even if the program was approved with the expectation that it would not achieve a TRC ratio of 1.0 (which would be the case with the REWH program).[61] Even the proponents of penalties did not propose to use the TRC ratio to set the required benchmark level of performance to avoid penalties. See Tr. at 938-40 (Brubaker).

RMI pointed out the difference between an incentive mechanism that included penalties for failing to meet a target level of performance, and a performance-based incentive mechanism under which the Commission establishes a baseline towards which the utility is being incented to move. Tr. at 857 (Datta). In RMI's view, the latter mechanism "will create the management

[61] However, not included in the shared savings mechanism as currently derived is any quantification of benefits such as job creation and reducing the use of fossil fuel related to the installation of solar water heating systems.

drive to achieve the programs because it aligns the DSM programs with the profit motivation of the corporation the same way supply side is aligned." Tr. at 858 (Datta). In other words, the utility is given the opportunity to "earn some return" on the achievement of DSM objectives, as the IRP Framework contemplates. Tr. at 859 (Datta). The goal is to assure that the utility, by virtue of implementing DSM programs, does not earn less profits (subject to a reasonable ceiling). Tr. at 860 (Datta).

D. LOST MARGINS

1. Recovery of Lost Margins

IRP Framework ¶III.F.2 provides that, under appropriate circumstances, the utility may recover the net loss in revenues sustained by the utility as a result of successful implementation of full-scale DSM sponsored or instituted by the utility. The IRP Framework further provides that the net revenue loss is the revenue lost less the variable fuel and operating expenses saved by the utility as a result of not having to generate the unsold energy. IRP Framework ¶¶III.F.2, 2.a.

Lost margins are referred to as "net lost revenues" in the IRP Framework, and equal the revenues lost as a result of sales reductions due to installing DSM measures, less the variable fuel and operating expenses saved by the utility as result of not having to generate the unsold energy. (The lost margin amount is the lost recovery of fixed costs.) Under appropriate circumstances, the IRP Framework allows the Commission to permit utilities to recover lost margins between rate cases. In a rate case, the impact of the existing energy efficiency programs on sales and revenues is reflected in the test year estimate of revenues (i.e., the test year sales are lower because of the ongoing impact of energy efficiency measures installed under our DSM programs). If rate cases were held every year, there would be no lost margins to recover between rate cases. See IRP Framework ; see also Tr. (8/31) at 817 (Hee).

In recognition of this, the National Association of Regulatory Utility Commissioners ("NARUC") adopted a resolution in 1989 urging state commissions to adopt appropriate mechanisms to compensate utilities for earnings lost through the successful implementation of DSM programs: HECO OB at 180-81.

In its rate case proposal, HECO proposed to change the manner in which lost margins were recovered, from a surcharge mechanism to a base rate mechanism, in order to meet its understanding of the intent of the DSM Stipulations. HECO also proposed to limit the amount of lost margins that could be recovered annually between rate cases, in order to address the criticism that the amount can grow indefinitely if there is no rate case.

Given the controversy that this issue has engendered, however, HECO no longer proposes to recover lost margins between rate cases. (Thus, the fixed cost shortfalls will have to be recovered through base rates in a general rate case when the impact of energy savings resulting from DSM programs is included in the test year sales estimate.) Nonetheless, the impact of lost margins is a significant issue when utility energy efficiency DSM programs are considered, and should be recognized in the design of utility compensation for the successful implementation of energy efficiency DSM programs.

RMI's position is that the utility should be allowed to recover its fixed costs determined in the applicable rate case with consideration for revenue erosion that results from energy efficiency program implementation. RMI OB at 3. Rather than continuing a mechanism for the recovery of lost margins between rate cases, however, RMI proposed that decoupling mechanism be implemented.

The Consumer Advocate contends that the impacts of the lost sales resulting from the implementation of energy efficiency and DSM programs between general rate applications (i.e., lost margins) should be considered only in the subsequent rate proceeding. CA OB at 9-10.

DOD does not believe that allowing recovery of lost margins in isolation is appropriate because (1) of the Commission's ruling on the motion for partial reconsideration of Interim D&O 22420, (2) an increase in DSM programs does not necessarily result in a reduction in HECO's total sales, (3) ratemaking is dynamic, and many things that affect the revenue requirement will change after rates are set, and (4) HECO confirmed that it did not require lost margin recovery in order for it to act professionally and pursue the appropriate combination of DSM and supply side resources. DOD OB at 3-4.

With respect to the first point, the Commission has assured HECO and the parties that the Commission "did not prejudge the issues in this proceeding when it issued Interim Decision and Order No. 22420." Order No. 22921 at 21-22.

The second point is irrelevant - DSM programs do not have to reduce sales to negatively affect profitability between rate cases. Any kwhs saved through an energy efficiency program reduce revenues that would have otherwise been recovered by the utility not only for the year in which the program was implemented, but also for some years into the future. This results in substantial opportunity loss (in terms of earnings potential) for HECO going forward and fewer kWh sold on which to recover fixed costs. When a successful program results in a large number of more energy efficiency measures being installed, the revenue impact on the utility can be quite large, and it persists into the future. As a result, it is important that appropriate financial compensation be provided for energy efficiency DSM program implementation. HECO should not be penalized financially for implementing cost-effective DSM instead of supply-side alternatives, which are allowed returns on installed plant and facilities. HECO OB at 193-94.

With respect to the third point, the analogy is not applicable. Expenditures for DSM programs are unique. Other utility expenditures are made in support of energy sales. In contrast, when a utility promotes effective energy efficiency DSM programs, energy sales are reduced from the levels that otherwise would have occurred. The reduced levels of energy use result in reduced costs to supply the energy, but also result in a larger reduction in revenue. This larger revenue loss includes a loss of the contribution to the fixed costs of the utility. Without an adjustment mechanism, the utility is financially worse off when it implements DSM programs. HECO OB at 180.

Expenses in future years may be higher than or lower than those assumed in setting rates. In contrast, lost margins will always have a negative impact, so the impact is asymmetric. More importantly, the better the job the utility does implementing energy efficiency DSM programs, the bigger the negative impact will be. Tr. (8/31) at 807, 810, 813 (Hee, Violette), citing EPA Report at 30.

The fourth point is comforting to opponents of lost margin recovery between rate cases, because it is used to support the assertion that the impacts of energy efficiency DSM programs should be simply ignored. Clearly, that is not the case, as has been recognized by the IRP Framework, NARUC, regulatory commissions in other jurisdictions, and entities that support the aggressive implementation of energy efficiency DSM programs.

With respect to the calculation of lost margins, there was some discussion during the panel hearings regarding possible methods to establish marginal costs for purposes of implementing a lost margins mechanism. However, RMI also acknowledged that, because there is no longer a lost margins mechanism being proposed by any party in this docket, "this matter may be moot and further discussion may be unnecessary." RMI OB at 29-30.

HECO agrees that the issue is moot. HECO also notes that, in D&O 14638, in which the Commission approved the initial C&I energy efficiency DSM programs, the Commission explicitly approved the methodology used to calculate lost margins. D&O 14638 notes that HECO's lost margins are recovered on a per unit forecast basis. The per unit lost revenues are calculated on the basis of two sets of parameters: (1) the unit lost margin on energy charges and (2) the unit lost margin on demand charges, calculated on a per unit basis. The unit lost margin energy parameter is calculated as the base energy rate, less fuel in base rates, less variable operations and maintenance (O&M) costs. D&O 14638 required that HECO file these unit lost margin parameters by rate schedule for energy and demand within 30 days of approval of the DSM program applications so that the estimates will be based on rate information current when the programs begin. D&O 14638 at 24-25. The unit cost method was adopted because it could be easily implemented using readily available values.

The D&O noted that the Consumer Advocate accepts HECO's recovery of net lost revenue methodology, "but only as an interim method until the commission considers and adopts a revenue decoupling mechanism." D&O 14638 at 26. The Consumer Advocate's representative at that time was Mr. Carl Freedman, who is a consultant for RMI in this proceeding.

HECO also notes that the forward-looking marginal costs provided in rate case marginal cost studies cannot be used to calculate the incremental fuel and variable O&M costs saved by not generating the kWhs saved as a result of the energy efficiency programs, as RMI attempted to do in its FSOP.

2. <u>Decoupling</u>

Revenue decoupling refers to separating the recovery of fixed costs from the amount of electricity sales. The argument is that if the recovery of fixed costs is no longer tied to sales, then the inherent utility conflict between selling more electricity to increase revenue and reducing sales through energy efficiency is eliminated.

While the concept of decoupling the recovery of fixed costs from sales is not hard to envision conceptually, the re-coupling effort is difficult to implement and is an example of a "devil is in the details" conundrum. How should the utility recover its fixed costs, if not through the sale of electrical energy?

Decoupling is complex. Some of the issues involved in decoupling include how to re-couple and whether to decouple all sales or sales only from selected customer classes. Additional issues include whether demand should be decoupled as well as energy, and the determination of the effect on ratepayers of the re-coupling mechanism. For example, depending on which customer classes are decoupled and which re-coupling index is used, the periodic reconciliation process could result in some customer bills increasing and other bills decreasing. HECO OB at 220.

Decoupling was addressed by the EPA Report. According to the EPA Report, decoupling requires two major steps for implementation: a "policy decision to separate energy sales from revenues", and "to recouple utility revenues to something other than actual kWh sales." EPA Report at 29. The EPA Report also noted that "The issues with decoupling are extremely complex and require a more comprehensive examination than provided in this document." EPA Report at 30. It also listed a number of key questions that need to be considered in decision making. Similar questions were highlighted in a March 2004 study, "Decoupling for Idaho Power Company", written by Eric Hirst, a copy of which was attached as Exhibit B to HECO's

Response to EPA Report.[62] Analyses cited in the report "show that decoupling replaces one set of factors unrelated to the determinants of fixed costs with another set of factors unrelated to those costs." Id. at 9.

In this proceeding, RMI was the principal proponent of decoupling, and proposed a decoupling method based on fixed revenue-per-customer.[63] Under this proposal, the utility would recover base revenue through its current rate schedules (i.e., through the base customer, energy, and demand charges). However, on a periodic basis, the revenue collected would be reconciled against the revenue calculated by multiplying the number of customers times a fixed dollar per customer revenue figure. The difference, if any, would be recovered/returned to ratepayers, resulting in electric utility revenues being determined by the fixed dollar per customer index.

RMI's proposal applied only to those rate schedules with a high percentage of margins in their volumetric rates, schedules R and G. The proposed decoupling mechanism did not apply to rate schedules J, H, PT, PP, PS and F, "because these schedules are already essentially 'decoupled' by way of the marginal block energy charges being close to HECO's marginal costs of energy production and delivery." RMI OB at 11.

In response, HECO noted that, while this recoupling of revenues to the number of customers sounds simple, an in-depth analysis would need to be performed in order to provide a reasonable assurance that this mechanism does in fact achieve the desired outcome. HECO OB at 219-20.

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[62] HECO's response to the EPA Report was filed August 22, 2006. A number of the criticisms of the decoupling mechanisms developed in other jurisdictions were identified during the panel hearings. See Tr. at 846-47, 849-50 (Freedman, Violette).

[63] RMI did not propose decoupling for large power or commercial customers. Tr. (8/31) at 894-95 (Freedman).

The Companies agree with the EPA that the policy decision to separate energy sales from revenues requires a more comprehensive examination, and have taken the position that it is not practical for that examination to occur within the current scope of the Energy Efficiency Docket. As noted by the EPA Report, decoupling revenue from sales necessarily involves recoupling revenues to another factor (presumably one that is related to costs), and the establishment of a mechanism to adjust rates for the difference. While the concept of decoupling is relatively straightforward, the mechanics of recoupling revenues to another factor, and the implications for customers and the utility, are much more complex. The Companies are open to reviewing some of these considerations in another forum, and/or in a collaborative working group, but the consideration and implementation of a specific decoupling mechanism should be considered by the Commission in a future general rate proceeding. HECO OB at 221.

RMI also acknowledges the novelty and complexity of issues regarding implementing a decoupling mechanism "and certainly does not wish to encourage the Commission to embrace a substantial new ratemaking mechanism without sufficient consideration." RMI OB at 11.

DOD is opposed to decoupling, based on contentions that disassociating revenues from sales volumes effectively shifts the risk of changes in economic conditions, variations in weather patterns, and all other factors that affect sales away from the electric utility to the customer, and decoupling experience in the past has been limited and unfavorable. DOD OB at 9-11. However, DOD also pointed out that no party proposes to subject Schedule P customers to decoupling. DOD OB at 10.

3. <u>Decoupling Follow Up</u>

Because of the complexities of the decoupling effort, a more comprehensive examination of decoupling was not undertaken or completed in this docket. However, in spite of these complexities, the Companies have begun to examine decoupling as an alternative to more frequent rate cases in order to fairly recover its fixed costs, taking into account the insight gained in this proceeding. See HECO FSOP at 72. HECO has retained consultants to help HECO analyze decoupling, and expects the analysis to take six to twelve months to complete. Tr. at 842 (Waller).

RMI contended that a proceeding should be implemented, within six months, to consider a decoupling mechanism for Hawaii's investor owned utilities to address the DSM revenue erosion issues framed by RMI in this docket. RMI OB at 3, 11-12.

RMI "acknowledges that a schedule of proceedings that would result in a final decision and order within a year is an aggressive schedule for some of the parties but reminds the Commission that schedules always take longer than originally established." RMI OB at 12.

The overall effort to produce a proposal for the Commission to consider would depend on the ability of a working group to come to a consensus on a schedule and consensus on the proposal. Tr. at 843 (Waller). One of the parties that would need to participate in the working group would be the Consumer Advocate, and the Consumer Advocate was unable to commit to a schedule for participating in such a working group. Tr. at 844-45, 851-52.

E. AMOUNT OF UTILITY COMPENSATION

1. HECO's Proposal

Under HECO's proposal, utility compensation would be based on 5% of the net benefits of the energy efficiency DSM programs, using the modified utility cost test. The utility would receive no compensation if it achieved less than 80% of the annual megawatt goal, there would be a cap on the incentive of $4 million before tax per year, and the compensation would be paid on a prospective basis, trued-up in the following year for actual achievements.

As a result of this proposal, HECO proposed to reduce its share of the savings by half, from 10% to 5%, in addition to foregoing the recovery of lost margins between rate cases. Based on the avoided costs provided in revised Exhibit 13 (rev. 8/24/06) to its FSOP, HECO estimated that a 5% share of the net benefits would be approximately $3.0 million annually assuming that the utility continues to be the administrator for all DSM programs.

The calculation of net benefits would use utility costs as program costs, excluding measurement and evaluation costs that would be incurred separately by the Commission. Utility compensation would also be excluded from program costs, because it is not a direct program cost, but rather the result of the performance-based compensation mechanism.[64]

The advantages posed by the shared savings mechanism include: (1) it is performance-based, such that higher energy savings and load reductions, and lower program costs result in greater levels of compensation; (2) the value of benefits are linked to actual system needs; and (3) the mechanism is currently in use and familiar to the Commission, Consumer Advocate, and the Company. HECO OB at 212 & n.105.

The 5% of net benefits would be based on regulatory judgment, and takes into consideration the cost measure used in the determination of the utility incentive. The range of percentages is 5 - 20 percent in other jurisdictions, so 5% is at the low end of the range. The 80% threshold was based on HECO's willingness to commit to a substantial amount of the energy efficiency goal before receiving compensation, as well as the recognition that there was a need to have a threshold. HECO OB at 215.

The compensation would not be paid to HECO unless the Company attained at least 80%

[64] DSM utility compensation is paid for by ratepayers, but should not be included in the costs used in the calculation of shared savings. A circular logic would result if utility compensation were to be considered a program cost for calculating net benefits for purposes of the compensation mechanism. Response to CA/HECO-IR-11; see also HECO's response to RMI/HECO-IR-6.

of the energy efficiency KW load reduction goal. Once the 80% threshold attainment level is reached, HECO would then be eligible for compensation as determined by the mechanism. Further, under either alternative, the amount of total compensation would be capped at $4.0 million before taxes. HECO OB at 213, <u>citing</u> HECO FSOP at 79.

An 80% threshold is a relatively high standard, and the Commission should determine if such a high threshold is appropriate. Dr. Violette testified that utility compensation should <u>not</u> be limited to when a utility achieves "superior" performance with respect to DSM programs, since that is not the case on the supply side, and would not create a level playing field for the expenditures with respect to DSM resources versus supply side resources. If net benefits are being provided to ratepayers, then the utility should receive some compensation. Tr. at 862-63 (Violette). In other words, whatever benchmark is set should not prevent the utility from earning some compensation on energy efficiency spending when the spending provides net benefits to ratepayers. Tr. (8/31) at 866 (Violette).

2. <u>RMI</u>

RMI initially proposed a utility compensation mechanism that was tied to avoided investment costs. It now accepts HECO's proposed mechanism, but proposed that incentives be capped at a level no greater than the utility shareholder earnings on ratebased supply side costs that the portfolio of DSM programs displaces. HSEA also believes that incentives should be based on and/or capped at the foregone earnings on displaced supply-side investments.

In HECO/RMI-FSOP-IR-142, RMI was asked to provide details on the incentives the utility would be allowed to earn from a "negawatt-hour" if the incentive was equal to the amount the utility would earn building new supply side resources to generate and deliver a kilowatt-hour to serve the same load. In its response, RMI stated that, "HECO earns the allowed return on equity times the equity proportion of capital for these investments."

RMI's utility compensation mechanism was tied to avoided investment costs, and assumed that decoupling was in place so that lost margin recovery did not have to be taken into consideration. Tr. at 942-43 (Freedman); see response to HECO/RMI-IR-142.

There was substantial discussion regarding the return on equity that the Company would forego as a result of implementing DSM programs. HECO also questioned RMI's calculation of the avoided return on equity, since RMI looked at annual revenue requirements and did not take into account the fact that the utility would receive a return on investment during every year the avoided plant was available. See Tr. at 900 (Violette), 143-46 (Freedman).

Conceptually, RMI made two errors in its calculations: (1) it applied the equity percentage to the revenue requirements, rather than to rate base and (2) it did not gross up for income taxes. In the "No Future EE DSM" case, the capital investment is made in 2015. In the "With Future EE DSM" case, the capital investment is made in 2024. The differential average rate base investments between the coal unit installed in 2015 ("No Future EE DSM" case) and the coal unit installed in 2024 ("With Future EE DSM case") can be calculated. To determine the amount equivalent to the foregone net income of investing in the coal unit, the equity percentage times the rate of return on equity should be applied to the average rate base difference between the two plans (rather than the annual revenue requirements difference). In order for shareholders to net the equivalent net income amount over the study period, the amount collected from ratepayers would also have to be grossed-up for income (and revenue) taxes.

In HECO's view, the foregone return on equity would not necessarily serve as a basis for setting the utility compensation (and could result in substantially more compensation then the Company is requesting if correctly calculated), but HECO committed to providing a calculation of avoided capital costs so that that information would be available to the Commission. See Tr. at 915, 917-20 (Hee).

HECO filed the calculation on November 3, 2006 as Exhibit C, and based the calculation on the deferral of a coal unit by HECO's proposed energy efficiency DSM programs. The calculation derives the utility's earnings from the installation of the coal unit, and derives equivalent levelized net income and revenue per kw of incremental DSM demand savings. In the "No Future EE DSM" case, the capital investment is made in 2015. In the "With Future EE DSM" case, the capital investment is made in 2024. This is a simplification of the avoided cost calculation submitted in CA/HECO-IR-9 on page 49 (rev. 8/24/06).

The filed worksheets show the differential average rate base investments between the coal unit installed in 2015 ("No Future EE DSM" case) and the coal unit installed in 2024 ("With Future EE DSM case"), and the differential costs (i.e. revenue requirements excluding revenue taxes) associated with the differential average rate base investments. In years 2015 to 2023, the average rate base is the rate base investment associated with the coal unit installed in 2015. In years 2024 and 2025, the negative average rate base is the difference between the remaining rate base investment (since accumulated depreciation is subtracted) associated with a coal unit installed in 2015 ("No Future EE DSM" case) minus the rate base investment associated with a coal unit installed in 2024 ("With Future EE DSM" case). The total differential cost is $316 million on a net present value ("NPV") basis.

To determine the amount for ratepayers to pay to be equivalent to the foregone net income of investing in the coal unit, the equity percentage times the rate of return on equity should be applied to the average rate base (rather than the annual revenue requirements, as RMI did). The determination of this foregone net income and the conversion to revenue is the second calculation. The foregone net income to shareholders during the 2006-2025 period resulting from the deferral of the coal unit by the energy efficiency DSM programs is $318 million, or $114 million on an NPV basis.

Return on equity applied to rate base provides the net income foregone by shareholders. In order for shareholders to net the equivalent net income amount over the study period, the amount collected from ratepayers must also be grossed-up for income (and revenue) taxes. The levelized amount that would have to be collected from ratepayers (including revenue taxes) is $3,136/incremental KW. This is the levelized amount that when multiplied by the annual incremental EE DSM load reductions results in an income stream that has the same net present value as the net present value of the net income foregone.

In order to receive the equivalent of the foregone earnings of $318 million on an NPV basis, shareholders would have to net over $10 million for every 6 MW of incremental load reduction achieved by its energy efficiency DSM programs. (Note that, unlike the recovery of the return of and on rate base that occurs each year through rates, this represents the one-time recovery of the foregone shareholder earnings for that increment of kw reduction.) The before tax amount would have to exceed $16 million per year. HECO's proposed utility compensation is far lower than that, and HECO has proposed that its utility incentive be capped at $4 million each year.

3. The Consumer Advocate

The Consumer Advocate alleged "that the level of additional compensation HECO seeks in the instant proceeding exceeds the overall rate of return and return on common equity that was stipulated to in Docket No. 04-0113." CA OB at 42. Apparently, the Consumer Advocate believes that the utility compensation for DSM should be compared to compensation paid on a one year certificate of deposit, and not to compensation for rate based assets, which is received for the lives of the assets. The Consumer Advocate then notes that 5% of net benefits calculated would equate to approximately 15% of HECO's $20 million DSM program costs. See CA OB at 42-43.

The utility is not being granted a "return" on a one year "investment" in demand-side resources. Rather it is being -

(1) compensated for successfully providing DSM services to its customers;

(2) compensated for foregoing the opportunity to earn a return on the supply-side resources displaced or deferred by demand-side resources;

(3) provided with an incentive to successfully compliment DSM programs, when such success directly reduces it s profitability between rate cases;

(4) compensated so that demand-side resources can compete for utility personnel and resources with supply-side resources as a profit center; and

(5) compensated for the risks encountered when a non-interconnected island-utility relies on customer-driven energy efficiency resources before adding supply-side resources.

A more appropriate basis for considering the amount of utility compensation is the "enterprise model". The enterprise model approach would recognize that the utility is being asked to operate under a different business model if energy efficiency becomes one of its areas of emphasis. The traditional utility is a capital-intensive enterprise that builds power plants and transmission lines and invests in distribution plant. The positions taken by the Commission (through the IRP Framework) and by the State of Hawaii (through its Energy Policy to reduce reliance on imported energy sources) demonstrate that they want the utility to also deliver energy efficiency and load management programs. This changes the traditional capital-intensive utility model and moves the model under which HECO operates toward a service enterprise. Dr. Violette's experience with service industry enterprises suggests that rates of return in the range of 10%-20% of <u>costs</u> are common. HECO OB at 205-06.

VI. CONCLUSION

Based on the foregoing and the entire record herein, HECO respectfully requests that the Commission: (1) approve HECO's proposed seven energy efficiency programs and authorize HECO to implement said programs and (2) approve HECO's proposed cost recovery and utility compensation mechanisms.

DATED: Honolulu, Hawaii, November 15, 2006.

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EXHIBIT "A"

REASONS WHY DSM PROGRAMS ACHIEVE LESS THAN 100% OF THE MAXIMUM ACHIEVABLE POTENTIAL ("MAP")

The reasons why DSM programs typically achieve less than 100% of the MAP differ somewhat depending on whether the MAP is for energy savings or for peak demand savings. Tr. (8/29) at 256-65 (Hempling, Hee, Wikler, Waller).

Energy Savings

The following factors contribute toward achieving less than 100% of the energy savings MAP:

(1) Less than ideal market conditions. Customer acceptance rates used for the MAP are based on a hypothetical upper-boundary that presumes ideal market conditions, e.g., rebate levels that achieve maximum customer acceptance, perfect knowledge and dissemination of information on the part of participants, the presence of appropriately skilled and proven trade allies, and the supply of energy efficiency products to meet the entire demand. Typically, ideal market conditions do not exist; therefore, achievement of 100% of MAP is not likely.

(2) For new programs, estimates of customer acceptance included in the MAP do not have the benefit of actual experience in the Hawaii market. Instead, experience from other non-local markets is used as the basis for those estimates. That experience may not translate completely to the local market, and may result in lower customer acceptance than assumed in the MAP analysis.

(3) Some end-uses included in the MAP estimate will not be addressed by the portfolio of DSM programs. DSM program designs generally do not target every end-use included in the MAP estimates to keep programs cost-effective, to enhance customer understanding, and to ease program administration. Thus, the market potential in some market segments will be untapped.

(4) Program marketing and outreach challenges may restrict communication to customers and lower the penetration rate below that envisaged in the achievable potential study.

(5) While the utility may try to ease the administrative burden placed on program participants to apply for and receive customer rebates, the effort to comply with documentation requirements can result in lower customer acceptance and participation rates.

EXHIBIT "A"

(6) For some programs that are targeted towards a specific customer segment, transaction costs can be high for activities such as recruiting smaller properties, conducting training workshops, spreading incentives across multiple organizations, maximizing measure comprehensiveness at measure installation sites, and so on. These are not anticipated at the time the achievable potential is estimated and may lead to unanticipated program costs and to attained savings that fall short of the achievable value.

Evidence from existing studies

An American Council for an Energy-Efficient Economy ("ACEEE") study surveying potential estimates across different US States found an electricity achievable savings potential of about 1.2% of existing levels of energy usage per year of program implementation.[1] This number was compared to actual savings achieved by leading utility programs. A 1995 analysis conducted by ACEEE found that the leading utilities were achieving energy savings of 0.5-1.0% per year, somewhat lower than the estimated achievable potential.[2] This implies that achieved savings as a percentage of MAP range from 42% to 83%.

Based on a review of ACEEE study reports, the table below compares the actual electricity savings as a percentage of total electric sales against the achievable potential as a percentage of electric sales. Data availability limitations restricted more extensive comparison across a larger number of states. Results point to the fact that in all cases actual electricity savings have fallen short of the achievable potential.

[1] See Steven Nadel, Anna Shipley & R. Neal Elliott, American Council for an Energy-Efficient Economy, The Technical, Economic and Achievable Potential for Energy-Efficiency in the U.S. – A Meta-Analysis of Recent Studies (2004), http://www.aceee.org/conf/04ss/rnemeta.pdf.

[2] See Stephen Nadel & Howard Geller, American Council for an Energy-Efficient Economy, Utility DSM: What Have We Learned, Where Are We Going? (1995).

Table 1: A comparison of actual savings vis-à-vis achievable potential

	Year	No. of years	Achievable potential (as % of sales)*	Actual electricity savings (as a % of sales)**	Actual as % of achievable
California	2003	10	10%	7.46%	74.6
Vermont	2003	10	31%	4.77%	15.4
U.S.	2000	20	24%	1.66%	6.9

*Source: Steven Nadel, Anna Shipley & R. Neal Elliott, American Council for an Energy-Efficient Economy, The Technical, Economic and Achievable Potential for Energy-Efficiency in the U.S. – A Meta-Analysis of Recent Studies (2004), http://www.aceee.org/conf/04ss/rnemeta.pdf.

**Source: Dan York & Marty Kushler, American Council for an Energy Efficiency Economy, ACEEE''s 3rd National Scorecard on Utility and Public Benefits Energy Efficiency Programs (2005), http://www.aceee.org/pubs/u054.htm.

Peak Demand Savings

Achievement of less than 100% of the energy savings MAP, as described above, is also likely to lead to less than 100% of peak demand savings MAP. The following additional factors that contribute toward achieving less than 100% of the peak demand savings MAP may result in further reductions, such that the percentage of demand savings MAP attained is typically less than the percentage of energy savings MAP attained.

(1) Demand coincidence with the system peak differs by measure. Customer energy usage patterns and certain program technology choices result in reductions in customer peak that may not be coincident with the system peak conditions.

(2) Customers have less experience with load management programs than with energy efficiency programs and are less informed about what their participation means for them (e.g., in an air-conditioning load control program the effect of a temperature increase during a load control event may result in unanticipated levels of occupant discomfort). Program designs may need to be adjusted in response to customer feedback to the initial programs.

(3) Certain customer types may appear to be attractive candidates to participate, and their potential savings captured in the MAP analysis. However, preliminary site assessments conducted during the program implementation stages may reveal site-specific technical constraints that could only be identified at the customer site. These restraints reduce customer participation below the potential savings assumed in the MAP analysis.

(4) Unexpected technology performance problems at sites that have chosen to participate reduce actual savings below estimates. For example, attempts to link incumbent energy management systems with coordinated remote notification and control platforms may be challenging and lead to lower peak demand savings.

(5) Higher-than-anticipated customer turnover rates in load management programs relative to energy efficiency programs may lead to lower levels of achieved demand. Unlike energy efficiency program participation for which energy savings are ensured for the life of the measure installed, customer participation and peak demand savings from a load management program require a continued decision by the customer to stay in the program. Thus, opportunities for termination are more numerous in a load management program and may lead to higher than anticipated turnover rates.

Examples of Energy Efficiency programs with actual program savings as a percentage of program goals

Brief Program Description	**kWh savings (actual as a % of goals)**	**kW savings (actual as a % of goals)**
San Diego Business Energy Services Team ("BEST") Program- a small commercial rebate program sponsored by the San Diego Regional Energy Partnership (SDREP) and administered by the San Diego Regional Energy Office (SDREO)	61%	26%
California's 2004-2005 Partnership for Energy Affordability in Multi-Family Housing ("the Partnership" or "the program").	72%	65%
California Agri-Food Energy Efficiency Program ("CAFEE") administered from 2004-2006- targeted Pacific Gas & Electric's (PG&E's) small, rural agricultural customers, organic farmers, and food processors.	99.5%	84.8%

Source: CALMAC Database, http://calmac.org.

CERTIFICATE OF SERVICE

I hereby certify that I have this date served a copy of the foregoing **REPLY BRIEF OF HAWAIIAN ELECTRIC COMPANY, INC., HAWAII ELECTRIC LIGHT COMPANY, INC. AND MAUI ELECTRIC COMPANY, LIMITED, EXHIBIT "A",** together with this Certificate of Service, by hand delivery and/or mailing a copy by United States mail, postage prepaid, to the following:

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